nationalgrid

Stage 02: Workgroup Consultation

Grid Code

GC0101: EU Connection Codes GB Implementation – Mod 2

What stage is this document at?

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

This proposal seeks to modify the Grid Code to comply with the obligations in the EU Connection Codes:

1. Set the Voltage & Reactive requirement in GB, as required in RfG; and HVDC; and
2. Set the Frequency requirements in GB, as required in RfG and HVDC

This document contains the discussion of the Workgroup which formed in June 2017 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 8 of this document.

Published on: **11 September 2017**
Length of Consultation: **15 working days**
Responses by: **2 October 2017**

High Impact:
Developers of: New generation schemes (800 Watts capacity and up), new HVDC schemes (including DC-connected Power Park Modules); GB NETSO; Distribution Network Operators

Medium Impact:
Transmission Owners (including OFTOs); Operators of existing generation, HVDC schemes considering modernisation

Low Impact:
None

Contents

Any questions?

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Timetable

The Panel have agreed the following timetable:

Workgroup Consultation issued to the Industry	11 September 2017
Modification concluded by Workgroup	7 November 2017
Workgroup Report presented to the Grid Code Review Panel	7 November 2017
Code Administration Consultation Report issued to	17 November 2017

the Industry	
Draft Final Modification Report presented to the Grid Code Review Panel	12 December 2017
Grid Code Review Panel Recommendation Vote	20 December 2017
Final Modification Report issued the Authority	5 January 2018
Decision implemented in the Grid Code	February 2018

About this document

This document is a Workgroup consultation which seeks the views of Grid Code and Distribution Code Users and interested parties in relation to the issues raised by the Original GC0101 Grid Code Modification Proposal which was raised by Richard Woodward, National Grid and developed by the Workgroup. Parties are requested to respond by **5pm** on **2 October 2017** to grid.code@nationalgrid.com using the Workgroup Consultation Response Proforma which can be found on the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0101/

Document Control

Version	Date	Author	Change Reference
0.1	11 July 2017	National Grid	Draft Workgroup Consultation
0.2	11 September 2017	Workgroup	Workgroup Consultation issued to Industry

1 Summary

1.1 This document describes the Original GC0101 Grid Code Modification Proposal (the Proposal) and the deliberations of the Workgroup.

1.2 GC0101 was proposed by National Grid and was submitted to the Grid Code Review Panel for their consideration on 30 May 2017 and the Distribution Code Review Panel on 8 June 2017.

1.3 The Grid Code Review Panel decided to send the Proposal to a Workgroup to be developed and assessed against the Grid Code Applicable Objectives.

1.4 Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

1.5 The Grid Code Review Panel detailed in the Terms of Reference the scope of work for the GC0101 Workgroup and the specific areas that the Workgroup should consider.

1.6 The table at page 37 outlines the EU RfG Articles and proposed Original solution.

2 Original Proposal

Section 2 (Original Proposal) is sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup Report contains the discussion by the Workgroup on the Proposal and the potential Solution.

Why

2.1 Guidance from BEIS and Ofgem was to apply the new EU requirements within the existing GB regulatory frameworks. This would provide accessibility and familiarity to GB parties, as well as putting in place a robust governance route to apply the new requirements in a transparent and proportionate way.

2.2 This modification needs to be undertaken in timely manner to ensure impacted users are aware of their design requirements, compliance obligations - particularly in relation to procurement of equipment, testing and operational requirements. This modification is also therefore, critical to facilitate/demonstrate member state compliance to these three EU network codes.

2.3 This proposal is one of a number of proposals which seek to implement relevant provisions of a number of new EU Network Codes/Guidelines which have been introduced in order to enable progress towards a competitive and efficient internal market in electricity.

2.4 Some EU Network Guidelines are still in development and these may in due course require a review of solutions developed for Codes that come into force beforehand. The full set of EU network guidelines are:

- Regulation 2015/1222 – Capacity Allocation and Congestion Management (CACM) which entered into force 14 August 2015
- Regulation 2016/1719 – Forward Capacity Allocation (FCA) which entered into force 17 October 2016

- **Regulation 2016/631 - Requirements for Generators (RfG) which entered into force 17 May 2016**
- Regulation 2016/1388 - Demand Connection Code (DCC) which entered into force 7 September 2016
- **Regulation 2016/1447 - High Voltage Direct Current (HVDC) which entered into force 28 September 2016**
- Transmission System Operation Guideline (TSOG) - entry into force anticipated Summer 2017
- Emergency and Restoration (E&R) Guideline - entry into force anticipated Autumn 2017

2.5 RfG, DCC and HVDC were drafted to facilitate greater connection of renewable generation; improve security of supply; and enhance competition to reduce costs for end consumers, across EU member states. These three codes specifically set harmonised technical standards for the connection of new equipment for generators, demand, and HVDC systems (including DC-Connected Power Park Modules respectively).

2.6 Significant work to progress GB understanding of the codes and consider the approach for implementation has been undertaken in Grid Code/Distribution Code issue groups **GC0048 (RfG), GC0087 (RfG Frequency) and GC0090 (HVDC).**

2.7 These have been widely attended, including DNOs and smaller parties. Additional stakeholder holder engagement has been undertaken to ensure the impacts of the three EU codes is understood, as well as to provide an opportunity to feed into the approach.

2.8 Through proposing these modifications under Open Governance, we will finalise our proposals; and undertake a final industry consultation to confirm they are appropriate, before submitting papers to Ofgem to request a decision

What

2.9 Full sections of the Grid Code, for example the Connection Conditions (CCs), and the Distribution Code and its daughter documents, will need to be extended to set out the new EU requirements to which impacted users will need to comply with. This will be a combination of completely new requirements inserted into the Grid and Distribution Codes, or adjustments/continuation of corresponding existing GB requirements to line up with equivalents in the new EU codes.

2.10 Proposed amendments to the Distribution Code and its associated Engineering Recommendations that implement the above requirements for users connected to distribution systems are also fully considered.

How

2.11 With the support of the industry, we will use this modification to finalise proposals to apply the EU Connection Codes requirements, before consulting with the wider industry and submitting to Ofgem for a decision. Previously, Grid Code and Distribution Code issue groups were formed in respect of GC0048 and Grid Code issue groups in respect of GC0087, GC0090 to:

1. Comprehensively review the code to form a local interpretation of the requirements;
2. Undertake a mapping between the EU and GB codes to understand the extent for possible code changes;
3. Form proposals, which will now be taken forward as formal modifications.

3 Solution

3.1 Section 3 (Solution) is sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup Consultation contains the discussion by the Workgroup on the Proposal and the potential Solution**.**

3.2 **Set the Voltage & Reactive requirement in GB, as required in RfG and HVDC**

Reactive Capability and Voltage Control in respect of HVDC Converters, DC Connected Power Park Modules and Remote End DC Converters

HVDC Connections (Title II) - Reactive Power Capability

The requirements for Reactive Power Capability are defined in Article 20 and Annex IV of the HVDC Code. In summary the principles and concepts for Reactive Power Capability for HVDC Connections are similar to those for Power Park Modules outlined in Article 21 of RfG which defines reactive capability in terms of voltage against Q/Pmax. . The principles and interpretation of these requirements are well articulated in Annex 2 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0048/ (GC0048 Voltage / Reactive Consultation).

Under the HVDC Code and RfG, the reactive capability is defined in terms of a Q/Pmax range rather than the current GB convention of Power Factor. The use of Q/Pmax does have the advantage that its value remains the same irrespective of the MW loading of the Generator or HVDC System unlike Power Factor which will vary as the MW loading starts to drop below its maximum.

To convert between Power Factor and Q/Pmax the following derivation is shown.

S = √3VI
Q = √3VISinϕ
P = √3 Cosϕ where the Power Factor is defined as Cosϕ

$$\frac{Q}{P} = \frac{\sqrt{3}\,VISin\varphi}{\sqrt{3}\,VICos\varphi} = Tan\varphi = Tan(arccos\varphi) = Tan(arcos\ (Power\ Factor))$$

Q/Pmax =Tan(arccos(Power Factor)

or

Power Factor = Cos[Arctan(Q/Pmax)]

Figure 5.2 below replicates Figure 5 of Annex IV of the HVDC Code and Table 5.3 replicates Table 6 of Annex IV.

ANNEX IV

Requirements for U-Q/Pmax-profile referred to in Article 20

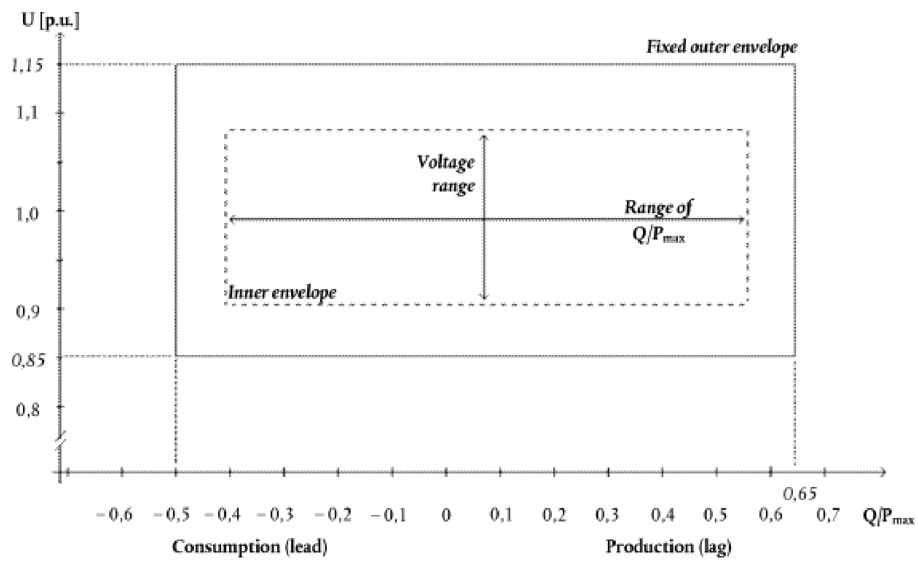


Figure 5: The diagram represents boundaries of a U-Q/Pmax-profile with U being the voltage at the connection points expressed by the ratio of its actual value to its reference 1 pu value in per unit, and Q/Pmax the ratio of the reactive power to the maximum HVDC active power transmission capacity. The position, size and shape of the inner envelope are indicative and shapes other than rectangular may be used within the inner envelope. For profile shapes other than rectangular, the voltage range represents the highest and lowest voltage points in this shape. Such a profile would not give rise to the full reactive power range being available across the range of steady-state voltages.

Figure 5.2 – Replication of Figure 5 of Annex IV of the HVDC Code

Synchronous Area	Maximum range of Q/Pmax	Maximum range of steady-state Voltage level in PU
Continental Europe	0,95	0,225
Nordic	0,95	0,15
Great Britain	0,95	0,225
Ireland and Northern Ireland	1,08	0,218
Baltic States	1,0	0,220

Table 6: Parameters for the Inner Envelope in the Figure.

Table 5.3 – Replication of Table 6 of Annex IV

In summary there is no real difference between the Reactive Power Capability for HVDC Connections in Article 20 and Annex IV of the HVDC Code when compared to Article 21 of RfG in respect of Power Park Modules other than the maximum Q/Pmax range available to TSO's in the HVDC Code is 0.95 whereas in the case of Power Park Modules the maximum Q/Pmax range is set to 0.66. The voltage range of 0.225 remains unchanged between both requirements. As the technology between HVDC Converters and Power Park Modules is similar, it is considered appropriate that the same values proposed for Power Park Modules are adopted for HVDC Connections which is the lesser of the two requirements. This characteristic is shown in Figure 5.3 below.

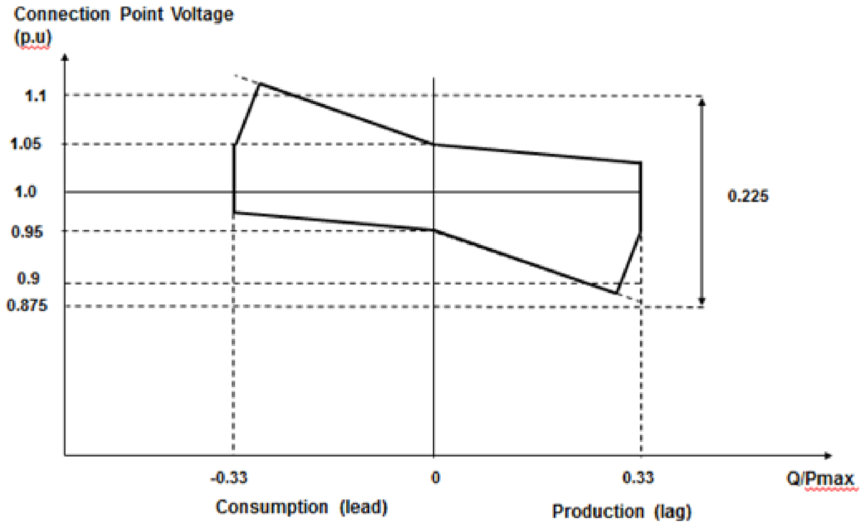


Figure 5.3 Proposed – U-Q/Pmax Profile for an HVDC Connection caught by the requirements of Title II of the HVDC Code.

For operation below Maximum Capacity the requirements of Article 20(4) of the HVDC Code would apply which again is similar to that of Article 21(3)(c)(iii) of the RfG. It is therefore proposed to adopt the same requirement as the GB proposal for a Type C and D Power Park Modules. This is shown in Figure 5.4 below.

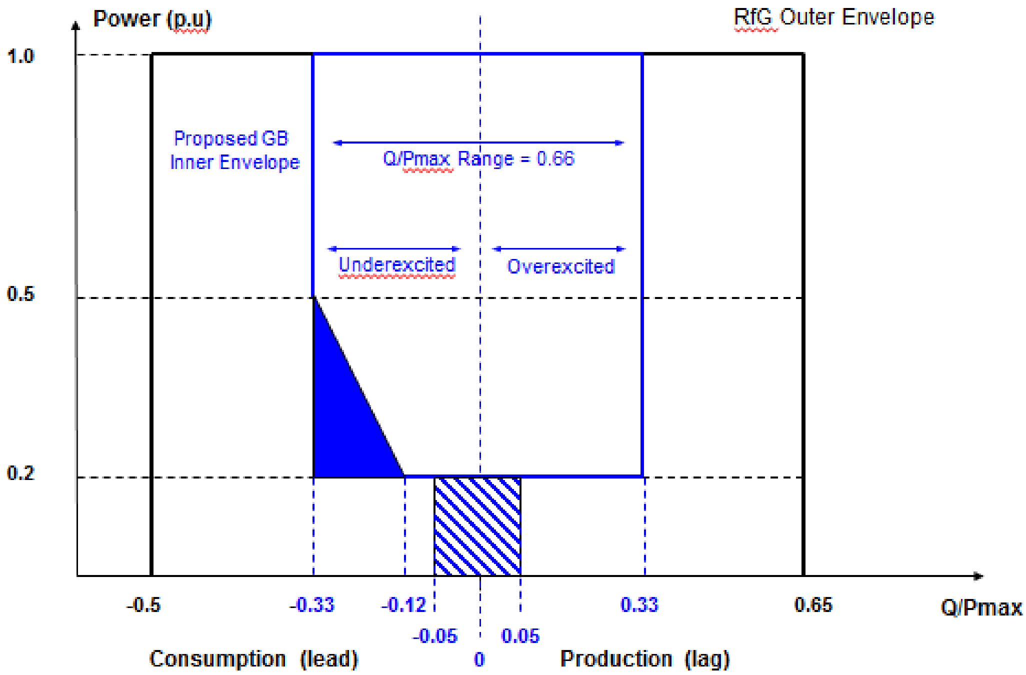


Figure 5.4 – Reactive Capability requirement for a HVDC Connection when operating below maximum output.

Article 21 of the HVDC Codes requires that the reactive power exchanged with the network at the connection point is limited to values specified by the Relevant System Operator in co-ordination with the relevant TSO and the reactive power variation caused by the reactive power control mode operation of the HVDC Converter Station shall not result in a voltage step exceeding the allowed value at the connection point.

The limits on these values and the maximum tolerable voltage step shall be agreed with the Relevant System Operator and the TSO. So far as the GB drafting is concerned, HVDC Converters would have to satisfy the requirements of CC.6.1.7 which relates to permissible voltage fluctuations at the Connection Point.

Voltage Control

Under Article 22 HVDC Converters (Title II) are required to be capable of operating in either Voltage, Reactive Power or Power Factor control mode. For GB implementation voltage control mode will be required. There is very little difference in the performance requirements stipulated for HVDC converters and Power Park Modules under RfG bar the range of values t1 for which 90% of the change in reactive power is set between 0.1 – 10 seconds and the value t2 is set between 1 – 60 seconds. In the case of RfG, the range of values of t1 is set to between 1 – 5 seconds and t2 is set between 5 – 60 seconds. As part of this GB Implementation it is proposed to set the requirements of HVDC Connections (Title II) to the same as Type C and D Power Park Modules which are t1 = 1 second and t2 = 5 seconds.

Reactive Power Control and Power Factor Control

These control modes of operation will normally be switched off but provisions will be made in the legal drafting to accommodate them if they are required for system reasons. For reactive power control mode and power factor control modes of operation the tolerance required in achieving target set point values is left to the discretion of the relevant System Operator.

On the GB Transmission System the preferred reactive control mode is voltage control. This has the advantage of controlling voltage at defined points across the network which is vital to enable the efficient transfer of real power. That said, the proposed solution for reactive control from generation is voltage control so there is no benefit to having voltage control provided by Generators and an alternative (eg Power Factor Control or Reactive Power Control) from HVDC Converter Technology.

In this case it is suggested that the same approach as RfG (Article 21(3)(d) of the RfG Code) for Type C and D Power Park Modules is adopted for HVDC Connections (Article 2 of the HVDC Code).

DC Connected Power Park Modules (Title III)

Article 38 of the HVDC Code states “The requirements applicable to offshore power park modules under Articles 13 to 22 of Regulation (EU)

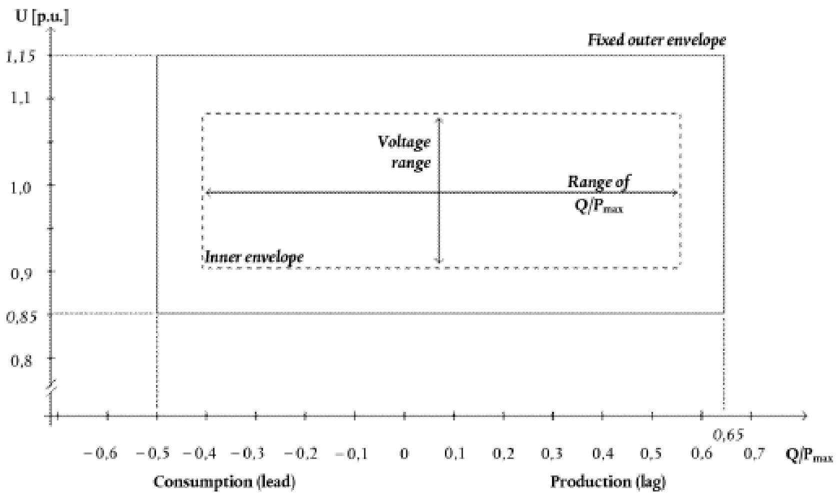
2016/631 shall apply to DC-connected power park modules subject to specific requirements provided for in Articles 41 to 45 of this Regulation. These requirements shall apply at the HVDC interface points of the DC-connected power park module and the HVDC systems. The categorisation in Article 5 of Regulation (EU) 2016/631 shall apply to DC-connected power park modules".

Regulation (EU) 2016/631 is the RfG Code, so in summary this statement means that DC Connected Power Park Modules are required to comply with the requirements of Articles 13 to 22 of RfG as applicable to Offshore Power Park Modules unless these are superseded by any additional requirements covered in Articles 41 to 45. It is however surprising that this text makes no reference to Articles 39 and 40 which is believed to be in error and will need to be confirmed with ENTSO-E..

Reactive Power Capability

The requirements for Reactive Power Capability for DC Connected Power Park Modules are defined in Article 40(2) and Table 11 of Annex VII of the HVDC Code.

Figure 5.4 below replicates Figure 7 of Annex VII of the HVDC Code and Table 5.5 replicates Table 11 of Annex VII.



L 241/64 EN Official Journal of the European Union 8.9.2016

Figure 7: U-Q/Pmax-profile of a DC-connected power park module at the connection point. The diagram represents boundaries of a U-Q/Pmax-profile of the voltage at the connection point[s], expressed by the ratio of its actual value to its reference 1 pu value in per unit, against the ratio of the reactive power (Q) to the maximum capacity (Pmax). The position, size and shape of the inner envelope are indicative and other than rectangular may be used within the inner envelope. For profile shapes other than rectangular, the voltage range represents the highest and lowest voltage points. Such a profile would not give rise to the full reactive power range being available across the range of steady-state voltages.

Figure 5.4 Replication of Figure 7 of Annex VII of the HVDC Code

Range of width of Q/Pmax profile	Range of steady-state Voltage level in pu
0-0,95	0,1-0,225

Table 11: Maximum and minimum range of both Q/Pmax and steady-state voltage for a DC-connected PPM

Table 5.5 replicates Table 11 of Annex VII

Article 40(2)(a) does include statements as to how the DC Connected Power Park Module shall achieve compliance when the DC Connected Power Park Modules are connected to one or more connection points.

For DC Connected Power Park Modules this is a tricky issue and the amount of reactive support required at the offshore connection point will be a function of the connection topology and size of the AC collector network. It also needs to be noted that due to the presence of the HVDC System between the remote converter end and Onshore end of the DC link there is no real benefit to the onshore system of a wide reactive range.

For DC Connected Power Park Modules, the principles for reactive capability are the same as those for Onshore HVDC Connections (Title II) and Power Park Modules under RfG .

In view of the complexities of this issue and noting the requirements of Article 38 of the HVDC Code it is proposed that the same approach be adopted as that for Configuration 1 and Configuration 2 AC connected Offshore Power Park Modules

For a radially connected DC Connected Power Park Module (i.e. equivalent to a Configuration I AC Connected Power Park Module as defined in RfG) this would require either (i) zero transfer of Reactive Power at the Grid Entry Point over a voltage range of 0.225pu of nominal or (ii) a reactive capability (with an associated steady state tolerance) which shall be in accordance with the U-Q/Pmax profile shown in Figure 5.5 below with the reactive capability and voltage range being agreed between the GB System Operator, the Generator and Offshore Transmission Licensee. Where such an alternative is agreed the value of the voltage range shall be no more than 0.225pu and the maximum Q/Pmax profile range shall be no more than 0 – 0.95.

The minimum requirement is to maintain zero transfer of reactive power at the Connection Point unless alternative values have been specified in which case the U-Q/Pmax profile shown in Figure 5.5 has to be met. For the reader it is worth noting that where a wider reactive range is specified then the requirements of the HVDC Code (Article 40(b)(i)) apply which places requirements on the TSO to specify the U-Q/Pmax profile required.

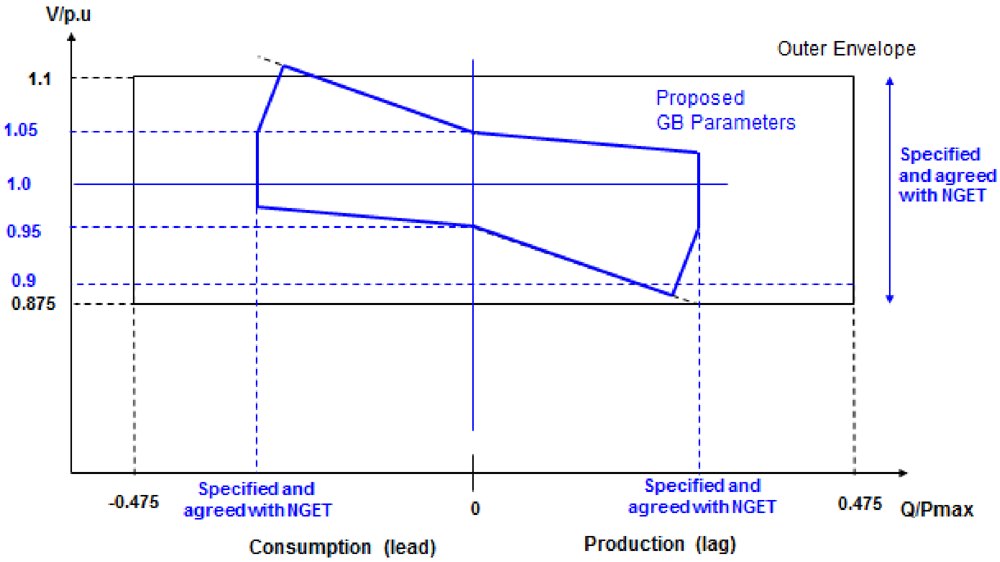


Figure 5.5

Figure 5.5 U-Q/Pmax profile with the values of Qmax and Qmin and Voltage range being specified in the Bilateral Agreement.

For a meshed connected DC Connected Power Park Module (i.e. equivalent to an AC connected Configuration 2 Power Park Module as defined in RfG) this would require either (i) the minimum reactive capability requirement applicable to an AC Connected Configuration 2 Power Park Module as defined in RfG at the Connection Point or (ii) a reactive capability (with an associated steady state tolerance) which shall be in accordance with the U-Q/Pmax profile shown in Figure 5.6 below with the reactive capability and voltage range being agreed between the GB System Operator, the Generator and Offshore Transmission Licensee. Where such an alternative is agreed the value of the voltage range shall be no more than 0.225pu and the maximum Q/Pmax profile range shall be no more than 0 – 0.95.

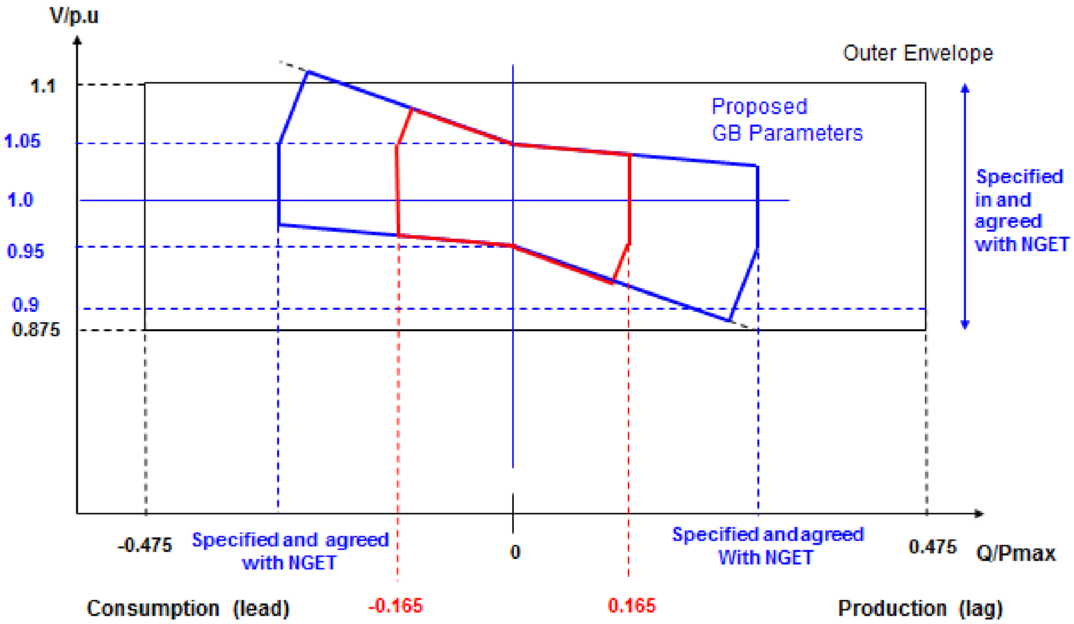


Figure 5.6 U-Q/Pmax profile with the values of Qmax and Qmin and Voltage range being specified and agreed with NGET. The minimum requirement is the red curve unless alternative values have been specified and agreed with NGET in which case the U-Q/Pmax profile shown in Figure 5.6 has to be met. The maximum permitted range of Q/Pmax is 0 – 0.95 and the maximum steady state voltage range is 0.1 – 0.225pu

Voltage Control, Reactive Power Control and Power Factor Control

Articles 39 – 45 of the HVDC Code do not specify any specific requirements in relation to voltage control, reactive power control or power factor control in respect of DC Connected Power Park Modules. It is, therefore concluded that the requirements of RfG (as stipulated under Article 38 of the HVDC Code which states that DC Connected Power Park Modules should satisfy the requirements of RfG as applicable to Offshore Power Park Modules) should apply and the proposal is therefore to adopt the GB proposal for RfG Type C and D Power Park Modules.

Remote End HVDC Converters (Title III)

Reactive Power Capability

Article 46 of the HVDC Network Code states that the requirements of Article 11 to Article 39 apply to remote end HVDC Converter Stations subject to the specific requirements provided for in Article 47 to 50.

In other words the requirements applicable to remote end HVDC Converter Stations are the same as those in Title II unless an alternative requirement has been specified in Articles 47 to 50 of the HVDC Network Code. It is surprising that Article 46 of the HVDC Network Code includes Article 38 and 39 which applies to DC Connected Power Park Modules and includes requirements from the RfG Network Code. This would infer that Remote End HVDC Converter Stations have to meet a large proportion of the RfG requirements. It is expected that this is an error which needs to be checked with the European Commission.

The requirements for Reactive Power Capability are defined in Article 48(2) and Annex VIII of the HVDC Code. In summary, the HVDC Code requirements follow the same requirements including as those applied for HVDC Connections (Title II) with the maximum Q/Pmax range being set at 0.95 and the maximum range of steady state voltage being 0.225pu. It is therefore proposed to adopt the values suggested for HVDC Connections under Title II which as mentioned above aligns with the RfG requirements for Power Park Modules.

Voltage Control, Reactive Power Control and Power Factor Control
Articles 46 – 50 of the HVDC Code do not specify any specific requirements in relation to voltage control, reactive power control or power factor control in respect of DC Connected Power Park Modules. It is, therefore assumed that the requirements of HVDC Connections (as stipulated under Article 46) apply and the proposal is to adopt the same approach as that for HVDC Connections.

Frequency Issues
For RfG, the Frequency issues were discussed as part of the GC0087 Consultation. Annex's 5, 6 and 7 of this report summarise the key frequency related parameters selected with the reasons why these values have been selected. The reasons as to why these values were selected is covered in detailing the GC0087 Consultation (Reference [2]).

As part of the GC0087 consultation, a number of responses were received. A response to these comments is provided in Annex 2 and the legal text has been updated as appropriate.

One specific point raised as part of the GC0087 consultation was that under RfG, the droop for Synchronous Power Generating Modules may be specified differently to that for Power Park Modules. This issue was discussed as part of the GC0087 work group and the simplest method is to make the value of Pref (as defined in RfG) the same as the maximum capacity for both Synchronous Power Generating Modules and Power Park Modules. For a Power Park Module this performance requirement would be reduced for the amount of turbines in service which follows current GB practice. The draft legal text has been updated to reflect this change. For operation in LFSM-O Mode it would also mean that the Power Output should start to drop off above 50.4Hz irrespective of the loading point of the Power Generating Module.

So far as HVDC is concerned, the proposal is to adopt the same frequency parameters as those recommended for RfG unless there is good reason not to do so for example where the HVDC Code specifies a different range or value.

HVDC is however complex in so far that it covers three elements – namely HVDC Connections (such as an Interconnector), DC Connected Power Park Modules (i.e. a Power Park Module connected behind an HVDC System) and requirements on Remote End DC Converters. In summary, several of the requirements (in particular frequency ranges) are more onerous than those in RfG. As part of this Workgroup report, a set of tables have been included in the Annex's which applies to Type A, B and C which provides a high level starting point of the suggested frequency parameter settings. Some of these values are mandated by the HVDC Code whilst others are subject to National choice.

HVDC Connections Title II

In terms of the frequency parameters there are a few issues worthy of special mention and these are summarised in the table below.

Frequency Range (Hz)	Setting	Comment
47 – 47.5Hz	60 seconds	Mandated under HVDC Code more onerous than current GB requirement of 20 seconds
47.5 – 49 Hz	Specified by TSO but longer than RfG. The RfG GB proposal is 90 minutes	Any value can be selected greater than 90 minutes. There is no materiality to National Grid of increasing this value. A value of 100 minutes has been suggested, it could be 91 minutes but this issue will be raised as a consultation question.
49 – 51 Hz	Unlimited	As per RfG
51 – 51.5Hz	Specified by TSO but longer than RfG. The RfG GB proposal is 90 minutes	Any value can be selected greater than 90 minutes. There is no materiality to National Grid of increasing this value. A value of 100 minutes has been suggested, it could be 91 minutes but this issue will be raised as a consultation question.

51.5Hz – 52Hz	To be specified by each TSO but longer than DC Connected Power Park Modules as specified under Article 39 which is 15 minutes.	Any value can be selected greater than 15 minutes. There is no materiality to National Grid of increasing this value. A value of 20 minutes has been suggested, it could be 16 minutes but this issue will be raised as a consultation question.
Rate of change of System Frequency	±2.5Hz/s measured over 1 second	Mandatory requirement under HVDC Code

The other frequency parameters are also covered in the annexes of this report but they are not believed to be so onerous. A consultation question has been raised as to whether the frequency related parameters are reasonable and if not what alternatives should be proposed.

DC Connected Power Park Modules Title III

In terms of the proposed frequency parameters and settings, these are summarised in Annex 7 of this report. In summary there are no fundamental differences here in the frequency settings between DC Connected Power Park Modules and those in RfG. The only notable exception is the Rate of Change of Frequency which is set at ±2Hz/s measured over a 1 second time period. This is a mandatory parameter which has been set by the HVDC Code.

A consultation question has been raised as to whether the frequency related parameters are reasonable and if not, what alternatives should be proposed.

Remote End HVDC Converter Stations (Title III)

For Remote End HVDC Converter Stations the proposed frequency parameters and settings are summarised in Annex 5 of this report. In summary they are the same as those for HVDC Connections under Title II.

A consultation question has been raised as to whether the frequency related parameters are reasonable and if not, what alternatives should be proposed.

3.3 **Previous consultations**

<u>GC0048 – RfG Voltage / Reactive</u>

The GC0048 RfG Voltage/Reactive Consultation was published on 27 December 2016; 12 responses were received, which are summarised in Annex 2 together with National Grid’s response. This report and legal text has been updated to reflect these comments where it is felt appropriate to do so.

<u>GC0087 – RfG Frequency</u>

This consultation was published on 20 April 2017; 4 responses were received, which are summarised in Annex 2 together with National Grid's response. This report and legal text has been updated to reflect these comments where it is felt appropriate to do so.

2. Set the Frequency requirements in GB, as required in RfG Type A and up;

RfG Article	Requirement	Range		Suggested GB Value		Interactions	Policy Req'd? (e.g. Non-compatibility to	Code Change req'd?
13.1(a)	Frequency Ranges	47 – 47.5Hz	20 seconds	47 – 47.5Hz	20 seconds	DCC; RfG Voltage & Reactive	No	No
		47.5 – 48.5Hz	90 minutes	47.5 – 49.0Hz	90 minutes			
		48.5 – 49.0Hz	TSO defined (not less than 90mins)	49.0 – 51Hz	Continuous			
		49.0 – 51.0Hz	Unlimited					
		51.0 – 51.5Hz	90 minutes	51.0 – 51.5Hz	90 minutes			
		51.5 – 52Hz	15 minutes	51.5 – 52Hz	15 minutes			
13.2	LFSM-O	Frequency threshold	50.2 – 50.5Hz	Frequency threshold	50.4Hz	HVDC; DCC	To define activation time in GC Note plant should start de-loading based on MW output not maximum rated Power Output	?
		Droop	2 – 12%	Droop	10% (2%/0.1Hz)			
		Activation delay	<2 s	Activation delay	<2s			
- 13.2(f)		DMOL						Y
13.3	Maintenance of Constant Active Power	49.5 – 50.5 Hz? – By interpretation		49.5 – 50.4Hz				Y
13.4-13.5	Power Output with Falling Frequency	Below 49Hz falling by a reduction rate of 2% of the Max Capacity at 50Hz/1Hz Freq. drop; Below 49.5Hz by a reduction rate of 10% of the Max		Power Output should not drop by more than pro-rata with frequency (i.e. max permitted requirement is 100% power at 49.5Hz falling linearly to 95% at 47.0Hz)				Y

Frequency Requirements – Type C and up

Article	Requirement	Range		Suggested GB Value		Interactions	**Policy** Req'd? **(e.g. non-compatibility to be defined)?**	**Code Change** Req'd?
15.2(c)	LFSM-U	Frequency Threshold	49.8–49.5Hz	Frequency Threshold	49.5Hz			
		Droop	2 – 12%	Droop	10%		Y	Y
		Initial Delay	<2s	Initial Delay	<2s			
15.2(d)	FSM	Active Power range	1.5 – 10%	Active Power range $\lvert\Delta P_1\rvert/P_{max}$	10%			
		Frequency Insensitivity	10 – 30mHz	Frequency Insensitivity $\lvert\Delta f_i\rvert$	±15mHz		Y	Y
		Frequency Insensitivity	0.02–0.06%	Frequency Insensitivity $\lvert\Delta f_i\rvert/f_n$	±0.03%			
		Deadband	0-500mHz	Deadband	0			
		Droop	2 – 12%	Droop	3 – 5%			
		Maximum admissible initial delay t1 for Generation with Inertia	2s	Maximum admissible initial delay t1 for Generation with Inertia	2s			
		Maximum admissible initial delay t1 for Generation without Inertia	TSO defined	Maximum initial admissible delay t1 for Generation without Inertia	1s			
		Full activation time t2	30s	Full activation time t2	10s			
15.2(g)	ASBMON	Status Signal (on/off)		Status Signal (on/off)				
		Scheduled Active Power output		Scheduled Active Power output				
		Actual value of Active Power output		Actual value of Active Power output				
		Actual parameter settings for Active Power Frequency Response		Actual parameter settings for Active Power Frequency Response			Y	Y
		Droop and deadband		Droop and deadband				
13.1(b)	RoCoF withstand	To be defined by the TSO		+/-1Hzs^{-1}		DCC	Y	Y

2. Set the Frequency requirements in GB, as required in RfG – Type A and up;

RfG Article	Requirement	Range		Suggested GB Value		Interactions	Policy Req'd? (e.g. Non-compatibility to be defined)	Code Change req'd?
13.1(a)	Frequency Ranges	47 – 47.5Hz	20 seconds	47 – 47.5Hz	20 seconds	DCC;	No	No
		47.5 – 48.5Hz	90 minutes	47.5 – 49.0Hz	90 minutes	RfG Voltage & Reactive		
		48.5 – 49.0Hz	TSO defined (not less than 90mins)	49.0 – 51Hz	Continuous			
		49.0 – 51.0Hz	Unlimited					
		51.0 – 51.5Hz	90 minutes	51.0 – 51.5Hz	90 minutes			
		51.5 – 52Hz	15 minutes	51.5 – 52Hz	15 minutes			
13.2	LFSM-O	Frequency threshold	50.2 – 50.5Hz	Frequency threshold	50.4Hz	HVDC; DCC	To define activation time in GC	?
		Droop	2 – 12%	Droop	10% (2%/0.1Hz)			
		Activation delay	<2 s	Activation delay	<2s			
- 13.2(f)		DMOL						Y
13.3	Maintenance of Constant Active Power	49.5 – 50.5 Hz? – By interpretation		49.5 – 50.4Hz				Y
13.4-13.5	Power Output with Falling Frequency	Below 49Hz falling by a reduction rate of 2% of the Max Capacity at 50Hz/1Hz Freq. drop; Below 49.5Hz by a reduction rate of 10% of the Max Capacity at 50Hz per 1Hz Freq drop		Power Output should not drop by more than pro-rata with frequency (i.e. max permitted requirement is 100% power at 49.5Hz falling linearly to 95% at 47.0Hz)				Y

Frequency Requirements – Type C and up

Article	Requirement	Range		Suggested GB Value		Interactions	Policy Req'd? (e.g. non-compatibility to be defined)?	Code Change Req'd?
15.2(c)	LFSM-U	Frequency Threshold	49.8–	Frequency Threshold	49.5Hz			
		Droop	2 – 12%	Droop	10%		Y	Y
		Initial Delay	<2s	Initial Delay	<2s			
15.2(d)	FSM	Active Power range	1.5 – 10%	Active Power range ιΔP1ι/Pmax	10%			
		Frequency Insensitivity	10 – 30mHz	Frequency Insensitivity ιΔfiι	±15mHz		Y	Y
		Frequency Insensitivity	0.02–0.06%	Frequency Insensitivity ιΔfiι /f_n	±0.03%			
		Deadband	0-500mHz	Deadband	0			
		Droop	2 – 12%	Droop	3 – 5%			
		Maximum admissible initial delay t1 for Generation with Inertia	2s	Maximum admissible initial delay t1 for Generation with Inertia	2s			
		Maximum admissible initial delay t1 for Generation without Inertia	TSO defined	Maximum initial admissible delay t1 for Generation without Inertia	1s			
		Full activation time t2	30s	Full activation time t2	10s			
15.2(g)	ASBMON	Status Signal (on/off)		Status Signal (on/off)				
		Scheduled Active Power output		Scheduled Active Power output				
		Actual value of Active Power output		Actual value of Active Power output				
		Actual parameter settings for Active Power Frequency Response		Actual parameter settings for Active Power Frequency Response			Y	Y
		Droop and deadband		Droop and deadband				
13.1(b)	RoCoF withstand	To be defined by the TSO		+/-1Hzs^{-1}		DCC	Y	Y

4 Workgroup Discussions

4.1 Workgroup

The Workgroup convened four times to discuss the issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Grid Code Applicable Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Proposer presented the defect that they had identified in the GC0101 proposal. The discussions and views of the Workgroup are outlined below.

The majority of the EU requirements captured in GC0101 have been previously consulted on via modifications GC0048 – RfG Voltage /Reactive and GC0087 - RfG Frequency Response. These were issue groups originally set up jointly under the Grid and Distribution Codes to engage with industry around the changes that would be required to the codes as a result of the implementation of the European Network Code (RfG) prior to the Open Governance Arrangements.

This report will address outstanding voltage and frequency requirements which have not yet been consulted on, notably the requirements arising from the HVDC Code. It will also attempt to address any issues raised by stakeholders during the previous consultations mentioned above. A table summarising the responses to the previous consultations and where the Proposer has addressed any concerns raised can be found in Annex 2.

This report includes the full proposed legal text for the EU requirements in question (i.e. GC0101 + GC0048 + GC0087) We are inviting responses to this Workgroup Consultation on the full solution outlined within this document.

In general the approach adopted will be to use the existing GB requirements unless there is a conflict with the RfG or HVDC code.

4.2 Definitions

A complex area of this work has been the management of definitions between the defined terms used in the EU Network Codes and those used in the GB national network codes, such as the Grid Code and the Distribution Code.

Article 2 of RfG includes a number of definitions which relate to physical quantities for example, voltage and current. RfG does however define these terms for example

"Voltage" means the difference in electrical potential between two points measured as the root mean square of the positive sequence phase to phase voltages at fundamental frequency"

"Current" means the rate at which electric charge flows which is measured by the root mean square value of the positive sequence of the phase current at fundamental frequency.

These definitions do create a number of issues, largely because there are many different connotations of these physical quantities. For example, in a three phase system the voltage could be the instantaneous phase to neutral voltage, the instantaneous phase to phase voltage, the positive phase sequence RMS voltage, the transient over voltage to name but a few. Similar issues arise with other physical quantities such as current. In these circumstances it was suggested by the Proposer that it was far better if the correct term as defined in IEC standards or equivalent are used.

This issue was discussed amongst the Workgroup on a number of occasions. In general the GB Codes do not define terms such as current or voltage as a result of the different set of circumstances under which they would apply. After advice was sought from the ENTSO-E code drafting team, some Workgroup Members set out that physical quantities or other standard engineering terms did not need to be re-defined to implement the EU Connection Codes, and that the current GB definitions could therefore be used. In the main this approach was accepted by the workgroup membership.

However, one Workgroup member was concerned that substituting GB definitions for those in the EU Network Codes may have unintended consequences, including that it could (i) amount to applying more stringent obligations[1] on 'new' connecting parties than required by the EU Network Codes and / or (ii) result in existing connected parties being obligated under the EU Network Codes without either (a) them having modified their facility to such an extent that their connection agreement required to be amended accordingly and / or (b) having not been the subject of a Cost Benefit Analysis undertaken in accordance with the EU Network Codes.

Some Workgroup members noted that whilst ENTSO-E's views on this topic were interesting, they had no vires to opine on this matter.

4.3 **RfG – Voltage Ranges**

RfG Article 16(2)(a) Tables 6.1 and 6.2 define the steady state voltage operating range for Type D Power Generating Modules. CC.6.1.4 of the Grid Code

[1] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (b) Removing More Stringent Requirements'.

currently defines the steady state operating range of all Users' connected to the Transmission System.

CC.6.1.4 and RfG Article 16(2)(a) Tables 6.1 and 6.2 are similar, other than the GB Code requires the voltage range applicable to User's connected below 132kV should be within ±6% - RfG requires Type D Power Generating Modules connected between 132kV and 110kV to remain within the limits of ±10%

It is not envisaged that this will have any significant impact on current GB practice as equipment rated at a nominal voltage of between 132kV and 110kV is generally not used.

Therefore, it is proposed that the Voltage Range requirement as defined in Grid Code CC.6.1.4 is maintained (ensuring consistency with the requirements of the ESQCR), accepting that CC.6.1.4 will require minor changes to ensure consistency with the European Codes. However, some Workgroup members were concerned that this would apply a more stringent[2] requirement on newly connecting parties.

HVDC

Under the HVDC Code, the requirements are split into three categories depending the type of equipment. These being HVDC Connections (Title II), DC Connected Power Park Modules (Title III) and Remote End HVDC Converters (Title III). A diagram showing the representation of these different arrangements is shown in Figure 5.1(a) and Figure 5.2(b).

Figure 5.1 (a) – Illustration of a HVDC Connection caught under the requirements of Title II of the HVDC Code.

[2] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

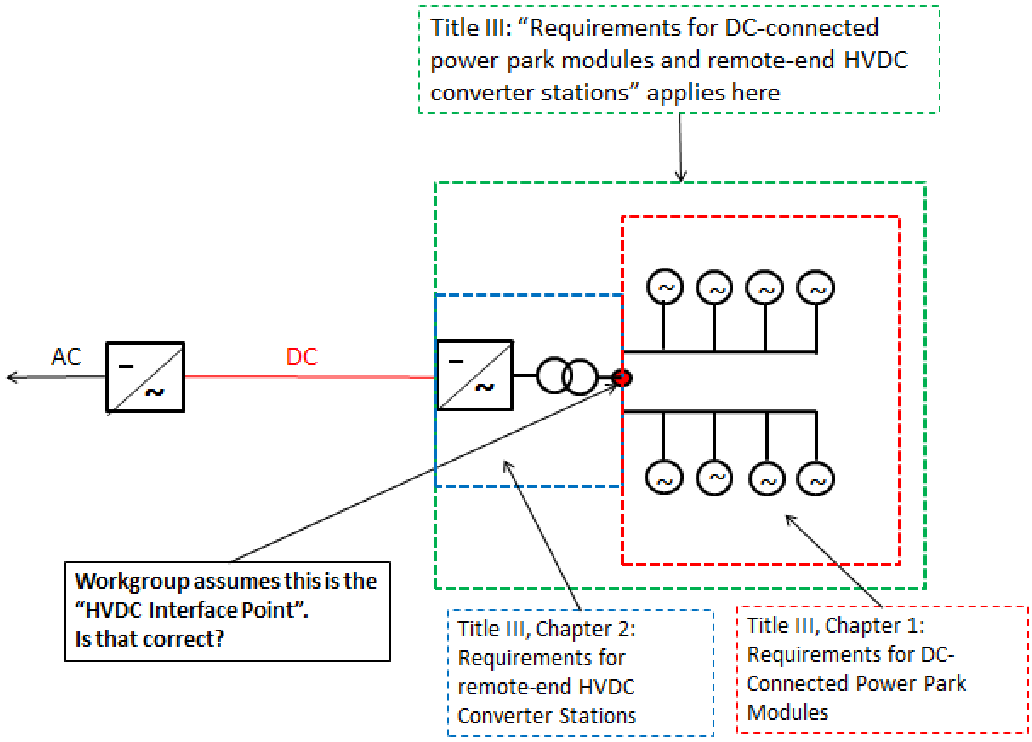


Figure 5.1(b) – Illustration of DC Connected Power Park Modules and Remote End HVDC Converter Stations caught under the requirements of Title III of the HVDC Code in addition to the appropriate definitions used under the HVDC Code.

HVDC Connections (Title II)

For HVDC Connections caught under Title II, the Voltage range requirements are defined under Article 18 and Tables 4 and 5 of Annex III of the HVDC Code which are replicated in Annex 6.

For the GB Synchronous Area the voltage ranges for HVDC Connections are the same as RfG and therefore it is suggested to adopt the same values as proposed for RfG.

DC Connected Power Park Modules (Title III)

For DC Connected Power Park Modules the voltage ranges are defined in Article 40 and Tables 9 and 10 of Annex VII which are tabulated below in Table 5.1(a) and Table 5.1(b).

Voltage Range (pu)	**Time Period for Operation**
0.85 – 0.90	60 minutes
0.90 – 1.10	Unlimited
1.10 – 1.118	Unlimited unless otherwise specified by the Relevant System Operator in co-ordination with the relevant TSO *(15 minutes proposed)*

1.118 – 1.15	To be specified by the relevant System Operator in coordination with the relevant TSO *(15 minutes proposed)*

Table 5.1(a) Minimum time periods for which a DC Connected Power Park Module shall be capable of operating for different voltage deviating from reference 1pu value without disconnecting from the network where the voltage base for pu values is from 110kV to (not including) 300kV.

Voltage Range (pu)	**Time Period for Operation**
0.85 – 0.90	60 minutes
0.90 – 1.10	Unlimited
1.05 – 1.15	To be specified by the Relevant System Operator in co-ordination with the relevant TSO. Various sub-ranges of voltage withstand capability can be specified *(15 minutes proposed)*

Table 5.1(b) Minimum time periods for which a DC Connected Power Park Module shall be capable of operating for different voltage deviating from reference 1pu value without disconnecting from the network where the voltage base for pu values is from 300kV to 400kV.

In summary there is little choice for the TSO other than in respect of the voltage range between 1.05 – 1.15pu. To ensure consistency with RfG and acknowledging that the voltage ranges are beyond those of RfG it is suggested that a 15 minute time period is proposed for these values. However, some Workgroup members were concerned that this would apply a more stringent[3] requirement on newly connecting parties.

<u>Remote End HVDC Converters (Title III)</u>

For Remote End HVDC Converters the voltage ranges are defined in Article 48 and Tables 12 and 13 of Annex VIII which are tabulated below in Tables 5.2(a) and Table 5.2(b).

Voltage Range (pu)	**Time Period for Operation**
0.85 – 0.90	60 minutes
0.90 – 1.10	Unlimited
1.10 – 1.12	Unlimited unless otherwise specified by the t System Operator in co-ordination with the relevant TSO *(15 minutes proposed)*
1.12 – 1.15	To be specified by the relevant System Operator in coordination with the relevant TSO *(15 minutes proposed)*

[3] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

Table 5.2(a) Minimum time periods for which a remote end HVDC Converter Station shall be capable of operating for different voltages deviating from reference 1pu value without disconnecting from the network where the voltage base for pu values is from 110kV to (not including) 300kV.

Voltage Range (pu)	Time Period for Operation
0.85 – 0.90	60 minutes
0.90 – 1.05	Unlimited
1.05 – 1.15	To be specified by the Relevant System Operator in co-ordination with the relevant TSO. Various sub-ranges of voltage withstand capability can be specified *(15 minutes proposed)*

Table 5.1(b) Minimum time periods for which a remote end HVDC Converter Station shall be capable of operating for different voltages deviating from reference 1pu value without disconnecting from the network where the voltage base for pu values is from 300kV to 400kV (included).

In summary there is little choice for the TSO other than in respect of the voltage range between 1.05 – 1.15pu. To ensure consistency with RfG and acknowledging that the voltage ranges are beyond those of RfG it is suggested that a 15 minute time period is proposed for these values. However, some Workgroup members were concerned that this would apply a more stringent[4] requirement on newly connecting parties.

4.4 **Specification of Wider Ranges**

<u>RfG</u>

RfG Article 16 (2)(b) does permit the relevant System Operator in coordination with the Generator and relevant TSO to specify wider voltage ranges or longer minimum operating times if economically and technically feasible.

In addition, Article 16(2)(c) states that the relevant System Operator in coordination with the Relevant TSO shall have the right to specify voltages at the connection point at which a Power Generating Module is capable of disconnection.

<u>HVDC</u>

<u>HVDC Connections (Title II)</u>
Article 18 of the HVDC Code does permit the System Operator in co-ordination with the relevant TSO to set wider ranges or longer minimum operating times.

In addition, HVDC Converters shall be capable of automatic disconnection at connection point voltages specified by the relevant Network Operator in coordination with the TSO. The terms and settings for automatic disconnection

[4] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

would need to be agreed between the System Operator, TSO and relevant HVDC System Owner.

This flexibility will be included in the legal drafting.

DC Connected Power Park Modules (Title III)
Article 40(1)(e) of the HVDC Code does permit wider voltage ranges and longer minimum operating times and conditions for disconnection and the voltage ranges applicable where other technologies are employed and the nominal frequencies are at a value other than 50Hz. In this case such requirements would need to be agreed with National Grid and the Relevant TSO (eg an OFTO) but would need to be in proportion to the values highlighted in Table 5.1 above.

Remote End HVDC Converters (Title III)
For remote end HVDC Converters, similar requirements would apply as per DC connected Power Park Modules as outlined in Article 48 (1)(d) of the HVDC Code. Wider voltage ranges or longer minimum operating times may be permitted but these would be agreed with National Grid and the Relevant TSO (eg an OFTO). For plant operating at nominal frequencies other than 50Hz, the time periods specified would be in proportion to those in Tables 5.2(a) and (b) above.

4.5 Operational conditions for simultaneous over voltage and underfrequency or simultaneous undervoltage and overfrequency

RfG

Article 16(2)(a)(ii) permits the Relevant TSO to specify shorter periods of time during which Type D Power Generating Modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and under-frequency or simultaneous under-voltage and over-frequency.

Both Type C and Type D Power Generating Modules are subject to the same reactive capability, and frequency range capability requirements. It therefore seems appropriate to apply the same voltage ranges (as per current GB practice) to Type A – C power generating modules too. However, some Workgroup members were concerned that this would apply a more stringent[5] requirement on newly connecting parties.

HVDC

Under the HVDC Code, there is no specific reference to combined frequency and voltage operating range other than in respect of DC Connected Power Park Modules (Article 38) which refer back to the requirements in RfG. The legal drafting will therefore be updated to reflect this requirement for DC Connected Power Park Modules.

[5] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

4.6 **RfG – Reactive Capability and Voltage Control**

Type B Synchronous Power Generating Modules - General Reactive Capability

Based on the discussions of the GC0048 Workgroup it was proposed that a reactive capability range of 0.95 Power Factor lag to 0.95 Power Factor lead at Rated MW output at the Connection Point should be adopted, unless otherwise agreed with the GB System Operator or the relevant Distribution Network Operator. This reactive capability range has been selected on the basis of DNO requirements, general plant capability and equitable treatment with Power Park Modules.

Type B Synchronous Power Generating Modules - Control Performance

Article 17(2)(b) requires Type B Synchronous Power Generating Modules to be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable set point without instability over the entire operating range.

In this context it is assumed that the entire operating range covers zero MW to Rated MW over the full reactive capability range (i.e. maximum lag (under-excited) to maximum lead (over-excited).

Practical implementation of a scheme would be dependent upon the requirement specified at the Connection Point by the Relevant Network Operator which could be voltage control, power factor control or reactive power control. However, some Workgroup members were concerned that this would apply a more stringent[6] requirement on newly connecting parties.

Type C and D Synchronous Power Generating Modules - Reactive Power Capability

When operating at maximum capacity, this is defined based on a U-Q/Pmax profile (i.e. a (voltage – reactive power)/Maximum Power Output profile) at the Connection Point.

Under RfG, the reactive capability is defined in terms of a Q/Pmax range rather than the current GB convention of Power Factor. The use of Q/Pmax does have the advantage that its value remains the same irrespective of the MW loading of the Generator unlike Power Factor which will vary as the MW loading starts to drop below its maximum. The same approach is alos adopted for Power Park Modules.

To convert between Power Factor and Q/Pmax the following derivation is shown.

[6] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

$S = \sqrt{3}VI$
$Q = \sqrt{3}VISin\phi$
$P = \sqrt{3}\ Cos\phi$ where the Power Factor is defined as $Cos\phi$

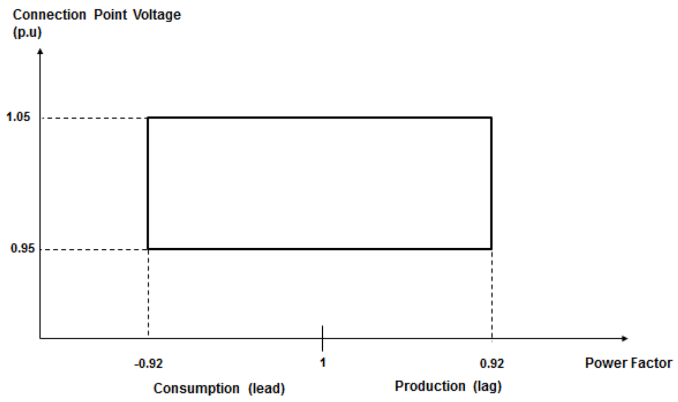
$$\frac{Q}{P} = \frac{\sqrt{3}\,VISin\varphi}{\sqrt{3}\,VICos\varphi} = Tan\varphi = Tan(arccos\varphi) = Tan(arcos\,(Power\ Factor))$$

$$Q/Pmax = Tan(arccos(Power\ Factor)$$

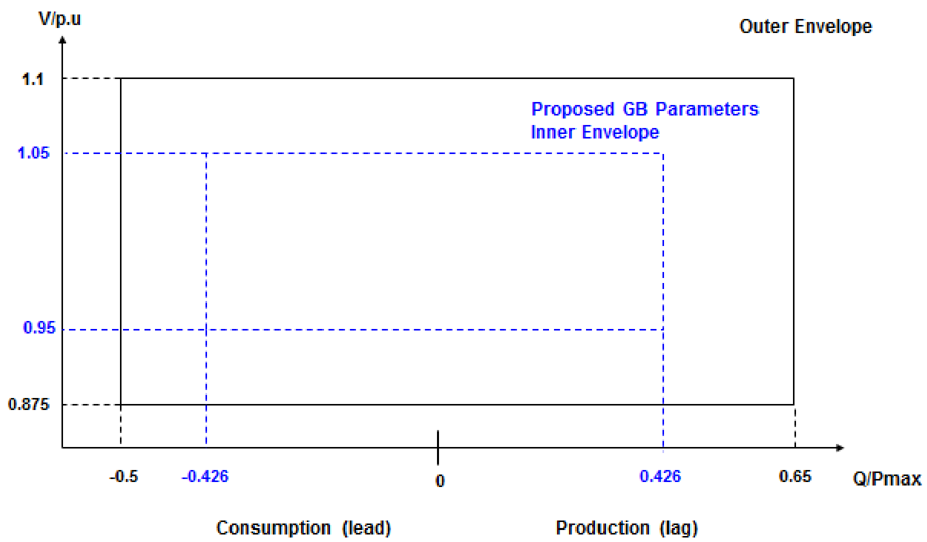
or

$$Power\ Factor = Cos[Arctan(Q/Pmax)]$$

For a Synchronous Power Generating Module, the proposed U-Q/Pmax profile adopted is shown below.



Translating this into a Voltage / Power Factor diagram results in the following diagram:



For operation below maximum capacity then Type C and Type D Synchronous Power Generating Modules would be required to follow the Generator Performance Chart.

Type C and D Synchronous Power Generating Modules – Excitaiton Performance Requirements

In GB the excitation performance requirements are specified in CC.A.6 of the Grid Code. The GB requirements are broadly the same as those specified in RfG other than in respect of a Stator Current Limiter which will require amendment to the legal text. This issue has been accounted for and included in the revised legal text. A summary of the RfG requirements and the current GB obligations are summarised in Table 6.21 below.

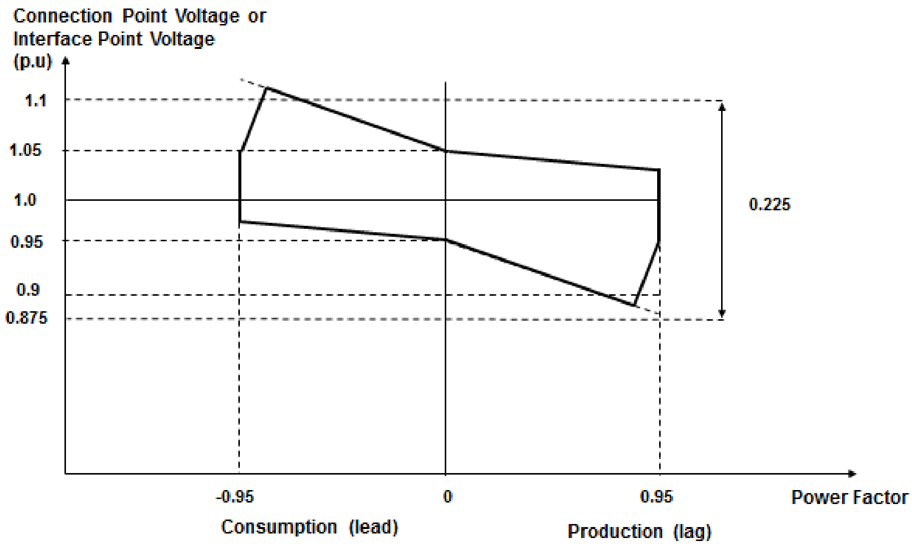
As part of RfG implementation it is proposed to have the same excitation performance requirements for Type C and D Power

Generating Modules other than in respect of Type C not requiring the need to

European Requirement	GB Requirement
Parameters and Settings including Transient and Steady State voltage control– (Art 19 (2)(a)&(b))	Steady State and Transient Voltage Control parameters covered in CC.A.6.2.3 and CC.A.6.2.4
Bandwidth limitation – (Art 19(2)(b)(i))	Bandwidth limitation – (CC.A.6.2.5.5)
Under Excitation Limiter – Art 19(2)(b)(ii)	Under Excitation Limiter – (CC.A.6.2.7)
Over Excitation Limiter – Art 19(2)(b)(iii)	Over Excitation Limiter – (CCA.6.2.8)
Stator Current Limiter – Art 19(2)(b)(iv)	Not explicitly defined
PSS Function – Art 19(2)(b)(v)	Power System Stabiliser – (CC.A.6.2.5)

have a Power System Stabiliser. The legal text has been updated to reflect this amendment.

U-Q/Pmax profile for a Type C or D Power Park Module with a Connection Point <u>above 33kV:</u>



Voltage/ Reactive Capability diagram for a Type C or D Power Park Module with a Connection Point <u>at or below 33kV</u> (NB most would be Distribution-connected)**:**

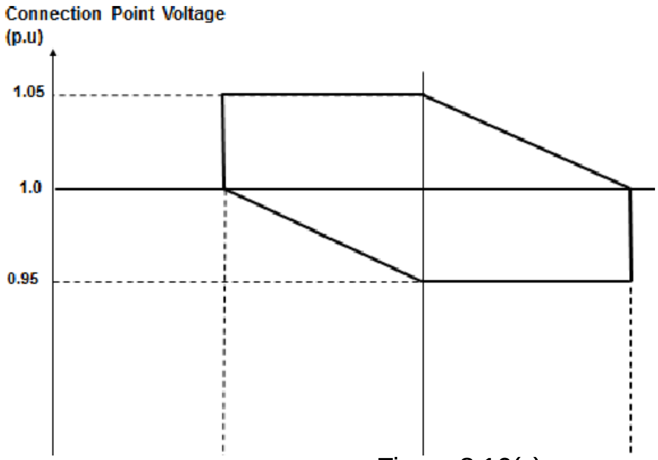


Figure 8.16(c)

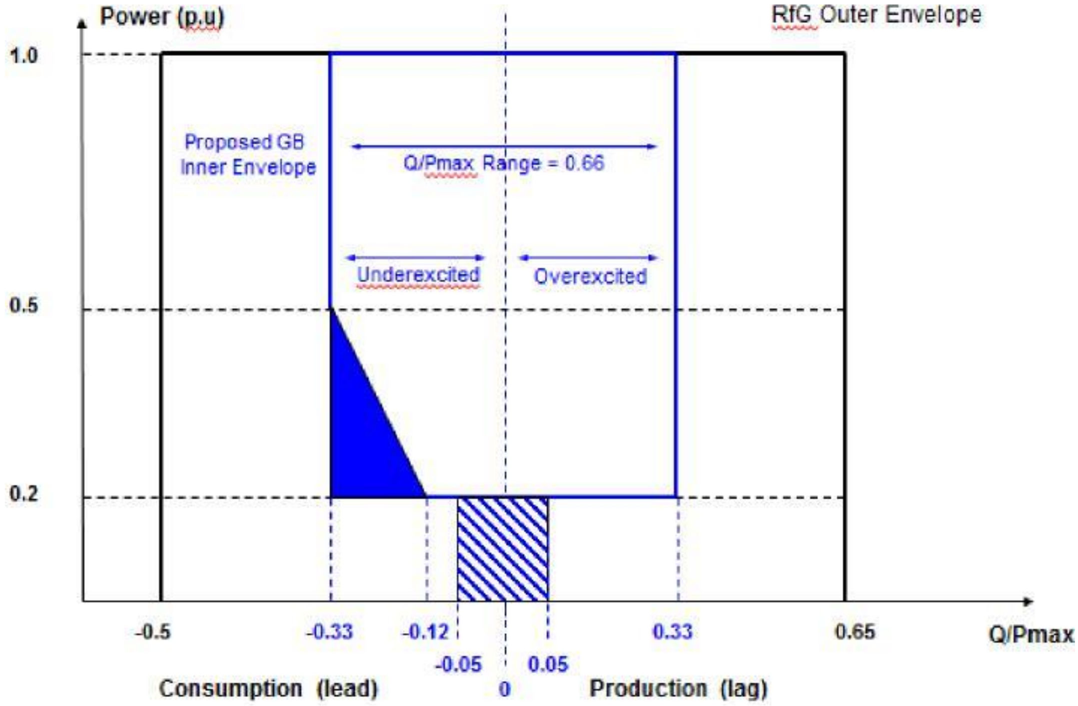
Type C and Type D Power Park Modules – Reactive Capability below Maximum Capacity

- When operating below maximum capacity, the PPM is required to satisfy a Power – Reactive Power / Pmax (P – Q/Pmax) requirement
- The current reactive capability requirements of CC.6.3.2 can be mapped directly into RfG Article 21(3)(c) other than conversion of Power Factor into Q/Pmax. However, some Workgroup members were concerned that this would apply a more stringent[7] requirement on newly connecting parties.
-

  The proposed GB requirement is therefore shown below

[7] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

P – Q Capability diagram of a Type C and Type D Power Park Module at the Connection Point



For Type C and Type D Power Generating Modules which are distribution connected, and not subject to a Connection Agreement with the GB System Operator, the Distribution Code may obligate such Generators to meet the requirements of the Grid Code through similar arrangements adopted for LEEMPS. However, some Workgroup members were concerned that this would apply a more stringent[8] requirement on newly connecting parties.

4.7 Type C and Type D Power Park Modules - Reactive Power Control Modes

There are three principle ways in which reactive power can be controlled from a Power Generating Module –

- voltage control;
- reactive power control; or
- power factor control

Under RfG Article 21(3)(d)(vii) the relevant System Operator in coordination with the Relevant TSO shall specify which of the above three reactive power control modes applies.

In general, voltage control is the principle reactive control method on the Transmission System. Going forward, this practice would continue to apply

[8] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

although flexibility would remain in the code for Power Factor control or Reactive Power control was necessary for site specific reasons.

4.8 Type C and Type D Power Park Modules Reactive Power Control

- As described above, Reactive Power Control will not be required from Type C and Type D Power Park Modules unless otherwise specified.
- Where a requirement for Reactive Power Control is specified, it would need to satisfy the requirements of RfG Article 21(3)(d)(v).

4.9 Type C and Type D Power Park Modules Power Factor Control

- Similar to Reactive Power Control, Power Factor control will not be required from Type C and Type D Power Park Modules unless otherwise specified in the Connection Agreement.
- Where a requirement for Power Factor Control is specified, it would need to satisfy the requirements of RfG Article 21(3)(d)(vi).

4.10 Type B Power Generating Modules General Reactive Capability requirements

- RfG - Article 20(2)(a) states “with regard to reactive power capability, the relevant System Operator shall have the right to specify the capability of a power park module to provide reactive power”.

4.11 Type B Power Park Modules Reactive Capability requirements

- RfG effectively leaves this choice to the relevant System Operator. For a Transmission-connected Power Park Module, current GB Grid Code practice would be for a reactive capability of 0.95 Power Factor Lag to 0.95 Power Factor Lead at Rated MW output at the Connection Point.
- For a DNO connected Power Park Module which falls outside the remit of the Grid Code, the GB reactive capability requirements are specified in the Distribution Code and G59/3.
- To ensure the requirements therefore remain as flexible as possible, it is proposed that Type B Power Park Modules would be required to have a reactive capability range of 0.95 Power Factor lag to 0.95 Power Factor lead at Maximum Capacity unless otherwise agreed with NGET or the relevant Distribution Network Operator.

4.12 Type B Power Park Modules Control Performance requirements

- RfG does not specify any form of reactive power control mode (e.g. voltage control, reactive power control or power factor control) from a Type B Power Park Module.
- As part of the GC0048 Workgroup, this issue was discussed at length and is covered in section 9.3 and 9.10 – 9.12 of the GC0048 consultation (Reference [1]). Voltage control would generally be the preferred choice for both Transmission and Distribution-connected generation, however the code has been drafted to allow the Relevant System Operator to determine the method of reactive control on a case by case basis and as the need arises .However, some Workgroup members were concerned

that this would apply a more stringent[9] requirement on newly connecting parties.

4.13 **Configuration, Voltage Range, Reactive Capability and Control performance requirements for AC Connected Offshore Power Park Modules**

Configuration

RfG Article 23 defines the requirements for AC connected Power Park Modules. These are classified into two categories:

Configuration 1: AC connection to a single onshore Grid interconnection point whereby one or more Offshore Power Park Modules that are interconnected offshore to form an Offshore AC System are connected to the Onshore System

Configuration 2: Meshed AC connections whereby a number of Offshore Power Park Modules are interconnected Offshore to form an Offshore AC System and the Offshore AC System is connected to the Onshore System at two or more Grid Interconnection Points.

For any Power Park Module which is connected to an HVDC System, the requirements of the HVDC Network Code shall apply.

4.14 **Offshore Voltage Range**

- RfG Article 25(1) defines the steady state voltage operating range for AC Connected Offshore Power Park Modules
- CC.6.1.4 of the Grid Code currently defines the steady state operating range of all User's connected to the Transmission System which includes Offshore Generating Units and Offshore Power Park Modules connected to Offshore Transmission Systems
- CC.6.1.4 and RfG Article 25(1) are similar, however the GB Code requires the voltage range applicable to User's connected below 132kV should be within ±6% and RfG requires AC Connected Offshore Power Generating Modules connected between 132kV and 110kV to remain within the limits of ±10%. However, some Workgroup members were concerned that this would apply a more stringent[10] requirement on newly connecting parties.
- It is not envisaged that this will have any significant impact on current GB practice where equipment rated at a nominal voltage of between 132kV and 110kV are generally used
- All other requirements relating to voltage range are the same as the onshore requirement

[9] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.
[10] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (a) Removing More Stringent Requirements'.

4.15 **Offshore AC Connected Power Park Modules Reactive Capability requirements**

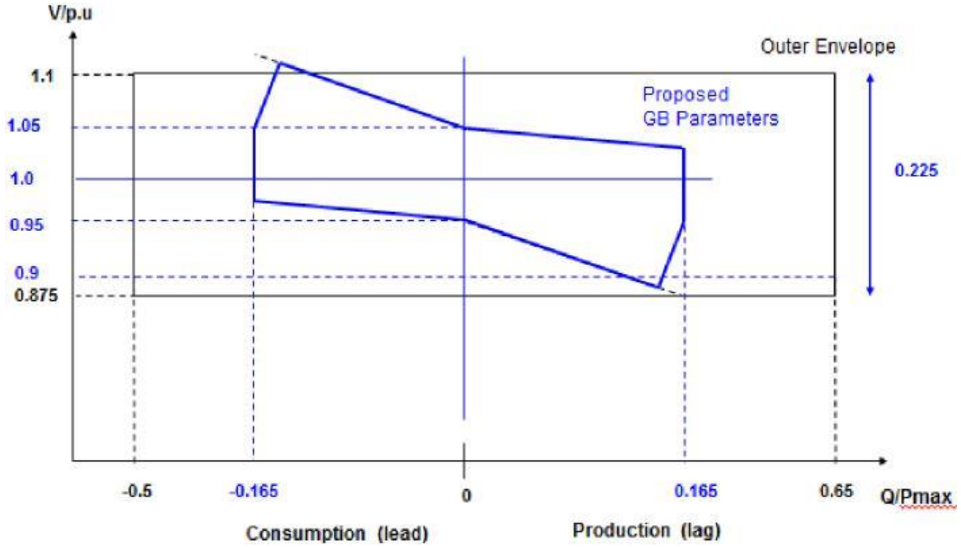
The Reactive Capability requirements for AC connected Offshore Power Park Modules are broadly the same as those for Type C and Type D Onshore Power Park Modules as defined in Article 21(3), other than in respect of the parameters which are redefined in Table 11 of RfG

For Configuration 1 Offshore AC Connected Power Park Modules the maximum range of Q/Pmax is set to zero (i.e. unity power factor) and for Configuration 2 Offshore AC Connected Power Park Modules the maximum range of Q/Pmax is set to 0.33.

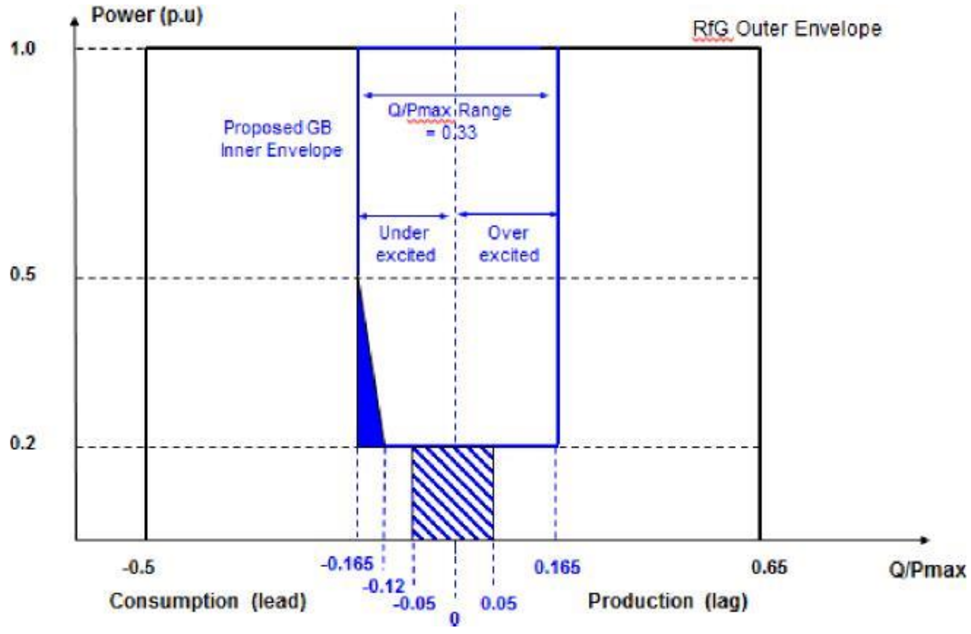
Both Configuration 1 and Configuration 2 have a maximum steady state voltage range of 0.225pu. The voltage range remains unchanged at 0.225pu. The following requirements for Configuration 2 AC connected Power Park Modules are shown below

As part of the GC0048 consultation one of the main comments received was the restricted capability particularly in respect of Configuration 1 AC Connected Offshore Power Park Modules being set at Unity Power Factor and the option of using a commercial agreement to utilise a wider range if agreed between National Grid, the Offshore Transmission Licensee and Generator. In respect of these comments it has been decided to update the legal text so that Offshore Generators (irrespective of whether they are configuration 1 or configuration 2) should meet the minimum requirement set out in the EU Network Codes but there is no restriction on generators providing, if they wish to, a wider range so long as this is agreed between the GB System Operator, the Offshore Transmission Licensee and Generator.

Configuration 2 - AC connected Offshore Power Park Module U-Q/Pmax Profile



Configuration 2 - AC connected Offshore Power Park Module P-Q/Pmax Profile



For Configuration 1 AC connected Power Park Modules the Reactive Capability at the Offshore connection point is fixed at unity power factor i.e. zero transfer of reactive power. There does not appear to be any tolerance (e.g. ±5%) on the tolerance of reactive power imported or exported to the transmission system

Notwithstanding this, Article 21(3)(d)(v) defines the requirements for Reactive Power control which states where reactive power control is employed, reactive power should be controlled with an accuracy of ±5 MVAr or ±5% of the full reactive power).

Interpretation of this requirement would therefore imply that this tolerance should also apply to Configuration 1 AC connected Offshore Power Park Module

5 Potential Alternatives

During the course of the first three Workgroup meetings a number of potential alternatives to the Original proposal were explored by members of the Workgroup. These potential alternatives were related to (a) banding and (b) removing more stringent requirements - these are explored further below. Additional potential alternatives may also arise from stakeholders, via the Workgroup consultation request(s), or other Workgroup members in due course.

These potential alternative options will be considered by the Workgroup and those potential alternatives that a majority of the Workgroup (or the Workgroup chair) believe better meet the Applicable Grid Code Objectives as compared to the Original will be taken forward as formal Alternatives to the Original proposal (meaning that they will be worked up, legal text prepared and, ultimately, they will be available for Ofgem to approve, if appropriate, and implemented).

(a) Removing More Stringent Requirements

At the second Workgroup meeting[11] the Proposer confirmed that it was the intention, with GC0101 that all the existing obligations placed on new connecting parties within the (GB) national network codes (such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc.,) would continue (with the GC0101 original proposal) to be applied to future parties connecting under the RfG, DCC and HVDC Network Codes. In other words the obligations in those EU Network Codes would be applied to future parties connecting as well as the additional national network code obligations - it was not intended that, in principle, any obligations for future connecting parties would be removed from the national network codes as a result of the GC0101 original proposal.

However, a Workgroup member identified that this appeared to be incompatible with the requirements of the Third Package, and in particular Articles 8(7) and 21 of Regulation 714/2009[12].

> *Article 8(7)*
> *"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****."* [emphasis added]
>
> *Article 21*
> *"This Regulation shall be without prejudice to the rights of Member States to maintain or introduce measures that contain* ***more detailed*** *provisions than those set out herein or in the Guidelines referred to in Article 18."* [emphasis added]

The Workgroup member highlighted that when the RfG was first drafted by ENTSOE (noting that the proposer of GC 0101, National Grid, was an active member of the RfG drafting team for ENTSOE) they had included an Article 7, which was subsequently deleted by the Commission on 14th January 2014.

That old Article 7 said the following:

> *"This Network Code shall be* ***without prejudice to the rights of Member States to maintain or introduce measures that contain*** *more detailed or* ***more stringent provisions than those set out herein****, provided that these measures are compatible with the principles set forth in this Network Code."* [emphasis added]

The Workgroup member noted that the wording of particular relevance to the current discussions are the parts emphasised in bold.

The Workgroup member stated that in their opinion it was clear, by their drafting, that ENTSOE intended to be able to maintain (or introduce later) requirements

[11] Held on 6th July 2017
[12] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

contained in the exiting national network codes[13] where those requirements were (or could be in the future) more stringent than the provisions set out in the EU Network Codes.

The Commission explicitly removed this proposed wording by ENTSOE.

Shortly after the Commission's deletion of the old Article 7 in January 2014, and at the prompting of GB stakeholders (including the Workgroup member who raised this potential alternative) Ofgem enquired of the Commission as to why that article had been deleted.

In their response dated 28th February 2014, the Commission wrote to Ofgem in the following terms which was shared with GB stakeholders

> *"1. that Article 21 of Regulation (EC) No 714/2009 already provided for the possibility for Member States to adopt* ***more detailed*** *measures and that there was thus no need to reiterate this possibility in the ENC RfG"* [emphasis added]

> *"2.* ***the adoption by Member States of measures more stringent than the ones of the ENC RfG*** *(to the extent of measures with cross-border trade effect)* ***would not be in line with Article 21 of Regulation (EC) No 714/2009****, i.e. if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"* [emphasis added]

Over a year later, on 26th June 2015, the RfG (and later the DCC and HVDC) Network Code was approved via the Comitology procedure, noting that in doing so, it:

> *"…**provide[s] a clear legal framework for grid connections**, facilitate Union-wide trade in electricity, ensure system security, facilitate the integration of renewable electricity sources, increase competition and allow more efficient use of the network and resources, for the benefit of consumers*"[14] [emphasis added]

As part of that approval process an arrangement was put in place by DECC (later BEIS) and Ofgem to canvass GB stakeholder views on any 'red line' items that the stakeholder(s) believed that DECC and Ofgem should seek to change in each of the respective EU Network Code prior to its approval. The Workgroup member could not recall National Grid identifying, as one of its 'red line' items, the need to allow for more stringent obligations (to those set out in the EU Network Codes) being placed on future connecting parties in GB.

The Workgroup member was also unaware of any other TSO in other Member States having, likewise, raised any similar concerns in respect of more stringent obligations in the intervening seventeen month period (from mid January 2014 to

[13] Such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc., in GB

[14] RfG, 14th April 2016, Recital 3

late June 2015) as the RfG Network Code was proceeding though the approvals process.

The Workgroup member stated that in the intervening seventeen month period TSOs could , if they believed this issue to be important, have put forward 'more stringent' obligations if they were required; such as those, for example, needed for maintaining the security of the electrical system; for inclusion in the EU Network Codes. If this had been done at the time then, as such, they would not, in law, be 'more stringent' in terms of Article 8(7) or Article 21 as any obligation(s) would not be in the national network codes (but rather in the EU Network Codes). However, this was not done by the TSOs, despite there being time for them to do so if they wished.

The Workgroup member went on to explain that as part of the implementation of the EU Network Codes arrangements have been put in place for stakeholder involvement going forward (this is, for example, set out in Article 11 of the RfG, Article 10 of the DCC and Article 11 of the HVDC).

As a result a ('combined') stakeholder committee for the three connections codes[15] (RfG, DCC and HVDC) was established in 2016. Chaired by ACER, with secretariat support from ENTSOE it brings together pan European trade associations etc., of stakeholders with interest in the three EU Network Codes relating to connections.

The Workgroup member stated that one of the questions that arose early on in the life of the connections codes stakeholder committee was around applying more stringent requirements within the national network codes.

This question was posed to the Commission in the following terms:

> *"Can a Member State impose more stringent requirements by a separate legislation than imposed by the network code Requirements for Generators (RfGNC)?"*

The Commission's answer to the question was provided in its presentation to the stakeholder committee on 8th September 2016 (which was subsequently repeated at the 9th December 2016 and 7th June 2017 meetings). The answer is as follows:

> "•**In general, no – not outside of the values provided for in the code**. [emphasis added]
>
> •But: "*the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner **may agree** on wider frequency ranges, longer minimum times for operation or specific requirements for*

[15] Further details, including papers / minutes etc., can be found at https://www.entsoe.eu/major-projects/network-code-implementation/stakeholder-committees/Pages/default.aspx

combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating module, if it is required to preserve or to restore system security." Article 13. [emphasis added]

•*"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****." Article 8, Regulation 714.*" [emphasis added]

This issue had also been brought to the attention of GB stakeholders in the spring of 2014 via a presentation which was given to meetings of the three relevant GB stakeholder bodies at that time (ECCAFF, JESG and the joint DECC/Ofgem Stakeholder Group).

That spring 2014 presentation was also shared with the GC0101 Workgroup prior to meeting 3[16] and can be found on the GC0101 National Grid website area. The Workgroup member highlighted a number of points in that presentation (some of which have been set out already in the above few paragraphs so are not repeated here), including:

– Firstly: burden of proof to say a particular "more stringent" national measure (over and above the ones of the ENCs) does not affect cross border trade resides with the Member State (not stakeholders)

– Secondly: the presumption for all "more stringent" national measures (over and above the ones of the ENCs) is that they are not legally binding unless and ***until the Member State*** *(not stakeholders)* ***has "proved*** *that there is no cross border trade effect"* [17][emphasis added]

"• In terms of Art 8 and Art 21 what do "...which do not affect cross-border trade..." and "... no cross border trade effect..."mean?

• Important to be mindful of very strong ENTSOe arguments about Type A generators – individually an 800W generator will not affect cross border trade but, cumulatively, they will have an affect on cross border trade" [18]

"• Single GB code requirement:*
– on one generator, maybe a case of there being no cross border affect?
– cumulatively on multiple generators, a case that there is an affect?

• Multiple GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

• All GB code requirements:*

[16] Held on 3rd August 2017
[17] Slide titled 'Another point of view (3)'
[18] Slide titled 'Another point of view (4)'

– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

** document(s) where national requirements are set out - such as GC, DC, DCUSA, BSC, CUSC, Engineering Recommendations (G59 / G83) etc."* [19]

In respect of the affect on cross border trade of obligating future connecting parties in GB, such as generators[20], to meet more stringent requirements than those set out in the respective EU Network Code, the Workgroup member highlighted to the Workgroup twelve examples of additional costs etc., which, in that scenario, a generator could (would?) face.

These examples were:

1) "pay for the extra obligations to be assessed and the solutions identified;

2) pay for the extra equipment or pay for the extra procedures to be developed to meet the extra obligations;

3) pay for the operation and maintenance of the extra equipment;

4) pay for the extra operational costs of the procedures (including extra staff);

5) pay for the extra equipment and procedures to be internally(*) tested (prior to the network operator compliance testing);

6) pay for the network operator's compliance testing of the extra equipment and procedures;

7) have to include a risk premium for items (5) and (6) in terms of if the tests are failed or delayed and either (a) remedial actions / costs are incurred to put this right and / or (b) the delay results in the plant not commissioning on time (delaying the revenue income being received);

8) in respect of (7) if the tests under items (5) and (6) fail, then pay for the extra equipment/ procedures changes plus the (re) testing of these elements (or the full rerun of the testing);

9) pay for the replacement costs of the extra equipment either at the end of its design life or if the equipment fails during its operational lifetime;

10) have to include a risk premium for the failure of the extra equipment resulting in the plant being non compliant and the plant being placed off line till the repairs or replacement can be undertaken;

11) in terms of (10) pay for the (re) testing (internal and / or compliance) of the repaired / replaced extra equipment; and (last, but not least)

[19] Slide titled 'Another point of view (5)'
[20] But not limited to generators - the DCC Network Code concerns demand connections and the HVDC Network Code deals with the connection of HVDC systems.

12) pay the capital cost for all these extra items above, noting that last time we look as an industry at this, the WACC of GB generators was over twice and in some cases more than quadruple that of network operators.

(*) the test is undertaken for the internal purposes of the generator, although the actual testing itself maybe undertake by an external provider, such as the equipment supplier."[21]

The Workgroup member noted that this list is not comprehensive and that other generators may identify additional items that have, inadvertently, been omitted. (e.g costs associated with compliance with other codes such as mandatory participation in the balancing mechanism for 132 kV connected generators in Scotland > 10 MW) (?)
In the view of the Workgroup member it was clear that the cumulative effect, of all these additional costs[22], on multiple generators in GB, would affect cross border trade; although the Workgroup member acknowledged, as per the Commission's statement[23] of 28th February 2014 to Ofgem, that it was not for the stakeholder, such as a generator, to prove that there was a cross border trade affect, but rather for *those who wish to apply more stringent requirements* (than those in the EU Network Codes) to prove that there is no cross border trade effect of doing so.

The Workgroup member was mindful that the GC0101 proposals would, in due course, be presented to the National Regulatory Authority (Ofgem) for determination. In this context, the Workgroup member was alive to the duty placed upon Ofgem (as the NRA for GB) "to ensure compliance with European Union Law". This was summarised under duties of the regulatory authority; in the Commission's interpretive note on Directive 2009/72 concerning the common rules for the internal market in Electricity (and the Gas equivalent) dated 22nd January 2010[24]; in the following terms:

> "Article 37(1)(b) of the Electricity Directive and Article 41(1)(b) of the Gas Directive state that the NRA has the duty of '*ensuring compliance of transmission and distribution system operators, and where relevant, system owners, as well as of any electricity and natural gas undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross border issues*'.
>
> It follows from this provision that, without prejudice to the rights of the European Commission as guardian of the Treaty on the functioning of the European Union, the NRA is granted a general competence — and the resulting obligation — as regards ensuring general compliance with European Union law. The Commission's services are of the opinion that

[21] Shared with the Workgroup by email on 3rd August 2017
[22] Arising from having to comply with the more stringent national network code obligations which go beyond what is required by the EU Network Code(s)
[23] *"if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"*
[24] https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_regulatory_authorities.pdf

Article 37(1)(b) of the Electricity Directive, and Article 41(1)(b) of the Gas Directive, are to be seen as a provision guaranteeing that the NRA has the power to ensure compliance with the entire sector specific regulatory '*acquis communautaire*' relevant to the energy market, and this vis-à-vis not only the TSOs but any electricity or gas undertaking."[25]

In light of the above, and given the statement from the GC0101 Proposer noted at the start of this item; together with the presentations (and associated discussions of the 'more stringent' point in terms of compliance) at the 24th July 2017 'Compliance with the RfG' hosted at the ENA; the Workgroup member believed that the original proposal (by virtue of not removing 'more stringent' requirements contained within the GB national network codes, that it was proposed to apply to future GB connecting parties) would be incompatible with EU law for the reasons set out above[26] and would thus also not better facilitate Grid Code Applicable Objective (d)[27]:

> *"To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency"*

Therefore, the Workgroup proposed to bring forward an alternative proposal to the GC0101 original proposal which would be to ensure that more stringent obligations contained within the GB national network codes would not be applicable to future connecting parties who fall within the scope of the RfG, DCC and HVDC Network Codes respectively; although, for the avoidance of doubt, those (GB) national network code obligations would continue to be applicable to 'existing' connected parties (as defined in the RfG, DCC and HVDC Network Codes respectively) unless and until they fall within the scope of the EU Network Codes for connection.

To set this in context the Workgroup member was mindful of the presentation given by the Proposer at the second Workgroup meeting setting out (in a tabular form) the items covered, in the case of generation, with the RfG Network Code for the four types of generation (A-D).

This table is shown below:

[25] Found at pages 14-15 of the Commission's interpretive note.

[26] As well as, potentially, with respect to Competition Law for the reasons outlined under Section 2 'Governance – Legal Requirements' in the GC0103 proposal: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0103/

[27] Or the Distribution Code equivalent Applicable Objective (iv).

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

Using this summary table, the Workgroup member identified that with the potential alternative that Type A generators would only be obligated, in terms of their connection to the grid, to those items shown in the table (and so on for Types B, C and D). All other items would be considered more stringent unless it could be proven that there was no cross border trade affect of obligating generators to comply with further obligations over and above those in the RfG (and likewise in terms of the DCC for Demand and the HVDC for HCDV connecting parties).

The proposer, whilst not agreeing with the workgroup member's 'more stringent' interpretation set out above, or indeed that their own solution is 'more stringent', is satisfied that the GC0100 workgroup, the wider industry (through this consultation), the respective Code Panels, and in due course, the National Regulatory Authority, are capable of considering the merits of the respective proposals and that this was fully discussed during the workgroup development of the proposal.

Alternative request Proposal form

Grid Code

Modification potential alternative submitted to: *(complete modification number this alternative is being submitted to)*

What stage is this document at?

01	Proposed alternative
02	Formal Workgroup alternative

GC0101

Mod Title: As per original (Removing More Stringent Requirements)

Purpose of alternative Proposal:
As per the Original.

Date submitted to Code Administrator: xxxx

You are: A Workgroup member

Workgroup vote outcome: Formal alternative/not alternative

(Should your potential alternative become a formal alternative it will be allocated a reference)

Any Questions?

Contact:

First Last

Code Administrator

First.Last @nationalgrid.com

00000 000 000

Alternative Proposer(s):

First Last

Company

First.Last @xxxxx.com

00000 000 000

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Should you require any guidance or assistance with this form and how to complete it please contact the Code Administrator at grid.code@nationalgrid.com

1 Alternative proposed solution for workgroup review

Removing More Stringent Requirements

This proposed alternative was raised at the second Workgroup meeting[1] where the Proposer confirmed that it was the intention, with GC0101 (original) that all the existing obligations placed on new connecting parties within the (GB) national network codes (such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc.,) would continue (with the GC0101 original proposal) to be applied to future parties connecting under the RfG, DCC and HVDC Network Codes. In other words, the obligations in those EU Network Codes would be applied to future parties connecting whilst retaining all existing national network code obligations. In short, it was not intended that, in principle, any obligations for future connecting parties would be removed from the national network codes as a result of the GC0100 original proposal.

However, a Workgroup member identified that this appeared to be incompatible with the requirements of the Third Package, and in particular Articles 8(7) and 21 of Regulation 714/2009[2].

> *Article 8(7)*
> *"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****."* [emphasis added]
>
> *Article 21*
> *"This Regulation shall be without prejudice to the rights of Member States to maintain or introduce measures that contain* ***more detailed*** *provisions than those set out herein or in the Guidelines referred to in Article 18."*
> [emphasis added]

The Workgroup member highlighted that when the RfG was first drafted by ENTSOE (noting that the proposer of GC0101, National Grid, was an active member of the RfG drafting team for ENTSOE) they had included an Article 7, which was subsequently deleted by the Commission on 14th January 2014.

That old Article 7 said the following:

> *"This Network Code shall be* ***without prejudice to the rights of Member States to maintain or introduce measures that contain*** *more detailed or* ***more stringent provisions than those set out herein****, provided that these measures are compatible with the principles set forth in this Network Code."* [emphasis added]

Of particular relevance to the currently discussions are the parts emphasised in bold.

It was clear, by their drafting, that ENTSOE intended to be able to maintain (or introduce later) requirements contained in the exiting national network codes[3] where those requirements were (or could be in the future) more stringent than the provisions set out in the EU Network Codes.

The Commission explicitly removed this proposed wording by ENTSOE.

Shortly after the Commission's deletion of the old Article 7 in January 2014, and at the prompting of GB stakeholders (including the Workgroup member who raised this potential alternative) Ofgem enquired of the Commission as to why that article had been deleted.

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[1] Held on 6th July 2017
[2] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

[3] Such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc., in GB

In their response dated 28th February 2014, the Commission wrote to Ofgem in the following terms:

> *"1. that Article 21 of Regulation (EC) No 714/2009 already provided for the possibility for Member States to adopt **more detailed** measures and that there was thus no need to reiterate this possibility in the ENC RfG"* [emphasis added]

> *"2. **the adoption by Member States of measures more stringent than the ones of the ENC RfG** (to the extent of measures with cross-border trade effect) **would not be in line with Article 21 of Regulation (EC) No 714/2009**, i.e. if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"* [emphasis added]

This response was shared by Ofgem with GB stakeholders (including the proposer of GC0101, National Grid) shortly after.

Over a year later, on 26th June 2015, the RfG (and later the DCC and HVDC) Network Code was approved via the Comitology procedure, noting that in doing so, it:

> *"…**provide[s] a clear legal framework for grid connections**, facilitate Union-wide trade in electricity, ensure system security, facilitate the integration of renewable electricity sources, increase competition and allow more efficient use of the network and resources, for the benefit of consumers*"[4] [emphasis added]

As part of that approval process an arrangement was put in place by DECC (later BEIS) and Ofgem to canvass GB stakeholder views (including from the proposer of GC0101, National Grid) on any 'red line' items that the stakeholder(s) believed that DECC and Ofgem should seek to change in each of the respective EU Network Code prior to its approval. The Workgroup member could not recall National Grid identifying, as one of its 'red line' items, the need to allow for more stringent obligations (to those set out in the EU Network Codes) being placed on future connecting parties in GB.

The Workgroup member was also unaware of any other TSO in other Member States having, likewise, raised any similar concerns in respect of more stringent obligations in the intervening seventeen month period (from mid January 2014 to late June 2015) as the RfG Network Code was proceeding though the approvals process.

Clearly in the intervening seventeen month period TSOs could , if they believed this issue to be important, have put forward 'more stringent' obligations if they were required; such as those, for example, needed for maintaining the security of the electrical system; for inclusion in the EU Network Codes. If this had been done at the time then, as such, they would not, in law, be 'more stringent' in terms of Article 8(7) or Article 21 as any obligation(s) would not be in the national network codes (but rather in the EU Network Codes). However, this was not done by the TSOs, despite there being time for them to do so if they wished.

As part of the implementation of the EU Network Codes arrangements have been put in place for stakeholder involvement going forward (this is, for example, set out in Article 11 of the RfG, Article 10 of the DCC and Article 11 of the HVDC).

[4] RfG, 14th April 2016, Recital 3

As a result a ('combined') stakeholder committee for the three connections codes[5] (RfG, DCC and HVDC) was established in 2016. Chaired by ACER, with secretariat support from ENTSOE it brings together pan European trade associations etc., of stakeholders with interest in the three EU Network Codes relating to connections.

One of the questions that arose early on in the life of the connections codes stakeholder committee was around applying more stringent requirements within the national network codes.

This question was posed to the Commission in the following terms:

> *"Can a Member State impose more stringent requirements by a separate legislation than imposed by the network code Requirements for Generators (RfGNC)?"*

The Commission's answer to the question was provided in its presentation to the stakeholder committee on 8th September 2016 (which was subsequently repeated at the 9th December 2016 and 7th June 2017 meetings). The answer is as follows:

> "•**In general, no – not outside of the values provided for in the code**. [emphasis added]
>
> •But: "*the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner* ***may*** ***agree*** *on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating module, if it is required to preserve or to restore system security." Article 13.* [emphasis added]
>
> •*"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****." Article 8, Regulation 714.*" [emphasis added]

This issue had also been brought to the attention of GB stakeholders (including the proposer of GC0101, National Grid) in the spring of 2014 via a presentation which was given to meetings of the three relevant GB stakeholder bodies at that time (ECCAFF, JESG and the joint DECC/Ofgem Stakeholder Group).

That spring 2014 presentation was also shared with the GC0101 Workgroup prior to meeting 3[6]. The Workgroup member highlighted a number of points in that presentation (some of which have been set out already in the above few paragraphs so are not repeated here), including:

> *– Firstly: burden of proof to say a particular "more stringent" national measure (over and above the ones of the ENCs) does not affect cross border trade resides with the Member State (not stakeholders)*
>
> *– Secondly: the presumption for all "more stringent" national measures (over and above the ones of the ENCs) is that they are not legally binding*

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[5] Further details, including papers / minutes etc., can be found at https://www.entsoe.eu/major-projects/network-code-implementation/stakeholder-committees/Pages/default.aspx

[6] Held on 3rd August 2017

*unless and **until the Member State** (not stakeholders) **has "proved** that there is no cross border trade effect"* [7][emphasis added]

"• In terms of Art 8 and Art 21 what do "...which do not affect cross-border trade..." and "... no cross border trade effect..."mean?

• Important to be mindful of very strong ENTSOe arguments about Type A generators – individually an 800W generator will not affect cross border trade but, cumulatively, they will have an affect on cross border trade" [8]

"• Single GB code requirement:*
– on one generator, maybe a case of there being no cross border affect?
– cumulatively on multiple generators, a case that there is an affect?

• Multiple GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

• All GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

** document(s) where national requirements are set out - such as GC, DC, DCUSA, BSC, CUSC, Engineering Recommendations (G59 / G83) etc."* [9]

In respect of the effect on cross border trade of obligating future connecting parties in GB, such as generators[10], to meet more stringent requirements than those set out in the respective EU Network Code, the Workgroup member highlighted to the Workgroup twelve examples of additional costs etc., which, in that scenario, a generator could (would?) face.

These examples were:

1) *"pay for the extra obligations to be assessed and the solutions identified;*

2) pay for the extra equipment or pay for the extra procedures to be developed to meet the extra obligations;

3) pay for the operation and maintenance of the extra equipment;

4) pay for the extra operational costs of the procedures (including extra staff);

5) pay for the extra equipment and procedures to be internally(*) tested (prior to the network operator compliance testing);

6) pay for the network operator's compliance testing of the extra equipment and procedures;

7) have to include a risk premium for items (5) and (6) in terms of if the tests are failed or delayed and either (a) remedial actions / costs are incurred to put this right and / or (b) the delay results in the plant not commissioning on time (delaying the revenue income being received);

[7] Slide titled 'Another point of view (3)'
[8] Slide titled 'Another point of view (4)'
[9] Slide titled 'Another point of view (5)'
[10] But not limited to generators - the DCC Network Code concerns demand connections and the HVDC Network Code deals with the connection of HVDC systems.

8) in respect of (7) if the tests under items (5) and (6) fail, then pay for the extra equipment/ procedures changes plus the (re) testing of these elements (or the full rerun of the testing);

9) pay for the replacement costs of the extra equipment either at the end of its design life or if the equipment fails during its operational lifetime;

10) have to include a risk premium for the failure of the extra equipment resulting in the plant being non compliant and the plant being placed off line till the repairs or replacement can be undertaken;

11) in terms of (10) pay for the (re) testing (internal and / or compliance) of the repaired / replaced extra equipment; and (last, but not least)

12) pay the capital cost for all these extra items above, noting that last time we look as an industry at this, the WACC of GB generators was over twice and in some cases more than quadruple that of network operators.

(*) the test is undertaken for the internal purposes of the generator, although the actual testing itself maybe undertake by an external provider, such as the equipment supplier."[11]

The Workgroup member noted that this list is not comprehensive and that other generators may identify additional items that have, inadvertently, been omitted. (e.g costs associated with compliance with other codes such as mandatory participation in the balancing mechanism for 132 kV connected generators in Scotland > 10 MW) (?)

In the view of the Workgroup member it was clear that the cumulative effect, of all these additional costs[12], on multiple generators in GB, would affect cross border trade; although the Workgroup member acknowledged, as per the Commission's statement[13] of 28th February 2014 to Ofgem, that it was not for the stakeholder, such as a generator, to prove that there was a cross border trade affect, but rather for *those who wish to apply more stringent requirements* (than those in the EU Network Codes) to prove that there is no cross border trade effect of doing so.

The Workgroup member was mindful that the GC0101 proposals would, in due course, be presented to the National Regulatory Authority (Ofgem) for determination. In this context, the Workgroup member was alive to the duty placed upon Ofgem (as the NRA for GB) "to ensure compliance with European Union Law". This was summarised under duties of the regulatory authority; in the Commission's interpretive note on Directive 2009/72 concerning the common rules for the internal market in Electricity (and the Gas equivalent) dated 22nd January 2010[14]; in the following terms:

"Article 37(1)(b) of the Electricity Directive and Article 41(1)(b) of the Gas Directive state that the NRA has the duty of '*ensuring compliance of transmission and distribution system operators, and where relevant,*

[11] Shared with the Workgroup by email on 3rd August 2017

[12] Arising from having to comply with the more stringent national network code obligations which go beyond what is required by the EU Network Code(s)

[13] "*if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so*"

[14] https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_regulatory_authorities.pdf

system owners, as well as of any electricity and natural gas undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross border issues'.

It follows from this provision that, without prejudice to the rights of the European Commission as guardian of the Treaty on the functioning of the European Union, the NRA is granted a general competence — and the resulting obligation — as regards ensuring general compliance with European Union law. The Commission's services are of the opinion that Article 37(1)(b) of the Electricity Directive, and Article 41(1)(b) of the Gas Directive, are to be seen as a provision guaranteeing that the NRA has the power to ensure compliance with the entire sector specific regulatory '*acquis communautaire*' relevant to the energy market, and this vis-à-vis not only the TSOs but any electricity or gas undertaking."[15]

In light of the above, and given the statement from the GC0101 Proposer noted at the start of this item; together with the presentations (and associated discussions of the 'more stringent' point in terms of compliance) at the 24th July 2017 'Compliance with the RfG' hosted at the ENA; the Workgroup member believed that the original proposal (by virtue of not removing 'more stringent' requirements contained within the GB national network codes, that it was proposed to apply to future GB connecting parties) would be incompatible with EU law for the reasons set out above[16] and would thus also not better facilitate Grid Code Applicable Objective (d)[17]:

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

Therefore, the Workgroup proposed to bring forward an alternative proposal to the GC0101 original proposal which would be to ensure that more stringent obligations contained within the GB national network codes would not be applicable to future connecting parties who fall within the scope of the RfG, DCC and HVDC Network Codes respectively; although, for the avoidance of doubt, those (GB) national network code obligations would continue to be applicable to 'existing' connected parties (as defined in the RfG, DCC and HVDC Network Codes respectively) unless and until they fall within the scope of the EU Network Codes for connection.

To set this in context the Workgroup member was mindful of the presentation given by the Proposer at the second Workgroup meeting setting out (in a tabular form) the items covered, in the case of generation, with the RfG Network Code for the four types of generation (A-D).

This table is shown below:

[15] Found at pages 14-15 of the Commission's interpretive note.

[16] As well as, potentially, with respect to Competition Law for the reasons outlined under Section 2 'Governance – Legal Requirements' in the GC0103 proposal: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0103/

[17] Or the Distribution Code equivalent Applicable Objective (iv).

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

Using this summary table, the Workgroup member identified that with the potential alternative that Type A generators would only be obligated, in terms of their connection to the grid, to those items shown in the table (and so on for Types B, C and D). All other items would be considered more stringent unless it could be proven that there was no cross border trade affect of obligating generators to comply with further obligations over and above those in the RfG (and likewise in terms of the DCC for Demand and the HVDC for HCDV connecting parties).

2 Difference between this proposal and Original

This proposal will ensure that the GB code changes set out in GC0101 are not more stringent than the requirements set out in the RfG.

3 Justification for alternative proposal against Grid Code objectives

As per original.

Impact of the modification on the Relevant Objectives:	
Relevant Objective	**Identified impact**
To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity	**Positive**
To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity)	**Positive**
Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole	**Positive**
To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	**Positive**
To promote efficiency in the implementation and administration of the Grid Code arrangements	**Positive**

In broad term the reasons why this proposal better meet the Applicable Objectives are as per the Original whilst, in addition, ensuring that the proposal is compliant with the Electricity Regulation and the EU Network (connection) Codes as the original proposal; in applying more stringent requirements on connecting generators, demand facilities and HVDC system than permitted by the EU Network (connection) Codes; is incompatible with the Electricity Regulation and the EU Network (connection) Codes.

Furthermore, when compared with the original, this alternative also better facilitates efficiency in the implementation and administration of the Code arrangements as it ensure that the solution to the Original defect is approvable and implementable.

4 Impacts and Other Considerations

As per the Original.

Consumer Impacts

As per the Original.

5 Implementation

As per the Original.

6 Legal Text

As per the Original, not yet agreed.

The proposer does however note that whilst various European treaties give the EU competence in the area of energy and creation of the internal energy market, competence on these matters is shared with the Member State. As a general principle therefore, the EU regulations do not encompass everything to do with energy; or mean that everything has to be, or should be, mandated at an EU level.

EU regulation 714/2009 and the Connection Codes themselves address this principle. Article 7 of RfG sets out 'Regulatory Aspects', including a provision in clause 3 that when applying the Regulation, Member States, competent entities and system operators shall: "(d) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;"

The proposer is therefore of the view that a test for stringency should solely be in respect of implementing the specific provisions in the Connection Codes. Other aspects subject to national legislation should not be subject to this test.

6 Impact & Assessment

Impact on the Grid Code

This modification is necessary to ensure the Grid Code is consistent with the applicable European Network Code requirements identified for this modification.

To apply these requirements, a new section to the Grid Code Connection Conditions specific to EU requirements will be introduced. Users bound by these EU requirements (as determined in the Network Codes themselves) will need to comply with this new section. Existing Grid Code Users will not be bound by this a new section to the Grid Code Connection Conditions specific to EU requirements (unless and until they fall within the scope of those EU Network Codes).

Impact on the Distribution Code

A similar approach will be taken with the Distribution Code. Existing generating equipment will continue to be bound by G59 and G83 (as appropriate to the equipment's size) which will remain unchanged. New generating equipment will be required to be compliant with two new documents, G99 and G98 (again as appropriate to size and/or compliance arrangements) which will only apply the RfG (and if appropriate HVDC) requirements to those parties in a way that that is not more stringent than the EU Network Code requirements.

Impact on Greenhouse Gas Emissions

The proposed modification should better facilitate connection of renewable low-carbon generation schemes in GB, thus having a positive impact on greenhouse gas emissions.

Impact on Core Industry Documents

Minor consequential changes are anticipated subsequent to this Grid Code modification in the STC and the Relevant Electrical Standards, to align them with the proposed changes.

Impact on EU Network Codes

This modification has been raised solely to implement EU Network Codes into existing GB regulatory frameworks in a way that is not more stringent than required by those Network Codes. It is therefore fundamental in ensuring GB Member State compliance with the EU Connection Codes specifically.

Impact on Consumers

This modification facilitates the implementation of consistent technical standards across the EU for the connection of new Generation or HVDC equipment. This should reduce development costs for new projects which should result in cost savings passed on to end consumers. Further consideration of compliance costs to these proposals is considered in the 'Costs of implementation' section below

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

The EU Network Code implementation is being undertaken as a significant programme of work within the GB industry. This mod forms part of that programme, but is not part of an on-going SCR.

7 Relevant Objectives – Initial assessment by Proposer

Impact of the modification on the Applicable Grid Code Objectives ():	
Relevant Objective	Identified impact (Positive/negative/neutral)
(a) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;	Positive
(b) To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);	Positive
(c) Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole;	Positive
(d) To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	Positive
(e) To promote efficiency in the implementation and administration of the Grid Code arrangements	Neutral

Impact of the modification on the Applicable Distribution Code Objectives:	
Relevant Objective	Identified impact (Positive/negative/neutral)
(i) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the distribution of electricity	Positive
(ii) To facilitate competition in the generation and supply of electricity	Positive
(iii) efficiently discharge the obligations imposed upon distribution licensees by the distribution licences and comply with the Regulation and any relevant legally binding decision of the European Commission and/or the Agency for the Co-operation of Energy Regulators; ; and	Positive
(iv) promote efficiency in the implementation and administration of the Distribution Code	Positive

The EU Connection Codes derive from the Third Energy Package legislation which is focused on delivering security of supply; supporting the connection of new renewable plant; and increasing competition to lower end consumer costs. It therefore directly supports the first three Grid Code and Distribution Code objectives.

Furthermore, this modification is to ensure GB compliance of EU legislation in a timely manner, which positively supports the fourth Grid Code and Distribution Code applicable objectives.

8 Implementation

Proposer's initial view:

This modification must be in place to ensure the requirements of the EU Connection Codes are set out in the GB codes by two years from the respective Entry Into Force dates (set out earlier in this paper).

It is therefore crucial that this work is concluded swiftly to allow the industry the maximum amount of time to consider what they need to do to arrange compliance.

Please note that this modification is required to be implemented on the 16 May 2018.

9 Workgroup Consultation Questions

The GC0101 Workgroup is seeking the views of Grid Code Users and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions:

1. Do you believe that GC0101 Original proposal better facilitate the Applicable Grid Code Objectives?
2. Do you support the proposed implementation approach?
3. Do you have any other comments?
4. Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider? If so the relevant form can be found at the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0101/

Specific GC0101 Workgroup Consultation questions:

5. As set out under 'Potential Alternatives - (a) Removing More Stringent Requirements' concerns have been expressed by some Workgroup Members that applying more stringent requirement on newly connecting parties (that fall within this scope of the EU Network Codes for generation, demand and HVDC systems) maybe incompatible with EU law. Do you have any views on this topic that could assist the Workgroup when they are considering the topic in due course?
6. Do you agree that the comments raised from the GC0048 voltage/reactive consultation have been addressed, in particular those relating to the Offshore reactive range. If not please advise why these issues have not been addressed

7. Do you agree that the comments raised from the GC0087 frequency response consultation have been addressed? if not please advise why these issues have not been addressed
8. Do you agree with the proposed voltage/ reactive and frequency requirements (including associated diagrams and parameters) captured under the HVDC Code are reasonable? If not please advise why.
9. Do you have any views on the time durations proposed for the frequency ranges defined in the Annex I of the HVDC Code? The time durations must be longer than those stipulated for RfG, however is there any materiality for an HVDC System in setting a value longer than that required under the RfG Code.
10. Do you believe it is reasonable to require HVDC Systems, DC Connected Power Park Modules and Remote End HVDC Converter Stations to meet similar requirements to Type D Power Park Modules defined under RfG? If not please state so.
11. Do you agree that the Offshore Transmission Arrangements (OTSDUW) should be included as part of the drafting?

Please send your response using the Response Proforma which can be found on the National Grid website via the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0101/

In accordance with Governance Rules of the Grid Code, Any Authorised Electricity Operator; the Citizens Advice or the Citizens Advice Scotland, NGET or a Materially Affected Party may (subject to GR.20.17) raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/Forms-and-guidance/

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **2 October 2017**. Your formal responses may be emailed to: grid.code@nationalgrid.com

If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response market "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Grid Code Review Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

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".

Please note that you can also send responses confidentially to the Authority.

References

[1] GC0048 Voltage / Reactive Consultation – Available at:-

http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589938215

[2] GC0087 Requirements for Generators Frequency Provisions – Available at:-
http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939924

Annex 1 – Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR GC0101 WORKGROUP

EU Connection Code Mod 2

Responsibilities

1. The Workgroup is responsible for assisting the Grid Code Review Panel in the evaluation of Grid Code Modification Proposal **GC0101, *EU Connection Code Mod 2*** tabled by National Grid at the Grid Code Review Panel meeting on 30 May 2017.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Grid Code Objectives. These can be summarised as follows:

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

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

   (iii) Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national; and

   (iv) To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency. In conducting its business, the Workgroup will at all times endeavour to operate in a manner that is consistent with the Code Administration Code of Practice principles.

Scope

3. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Grid Code Objectives.

4. In addition to the overriding requirement of point 3 above, the Workgroup shall consider and report on the following specific issues:

   a) Implementation;
   b) Review draft legal text should it have been provided. If legal text is not submitted within the Grid Code Modification Proposal the Workgroup should be instructed to assist in the developing of the legal text; and
   c) Consider whether any further Industry experts or stakeholders should be invited to participate within the Workgroup to ensure that all potentially affected stakeholders have the opportunity to be represented in the Workgroup.

   Modify the Grid Code and Distribution Code to specify in GB:*
   d) the Voltage and Reactive requirements under RfG and HVDC
   e) the Frequency requirements under RfG and DCC

5. As per Grid Code GR20.8 (a) and (b) the Workgroup should seek clarification and guidance from the Grid Code Review Panel when appropriate and required.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative Grid Code Modifications arising from Group discussions which would, as compared with the Modification Proposal or the current version of the Grid Code, better facilitate achieving the Grid Code Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative Grid Code Modification which appears in the Governance Rules of the Grid Code. The definition entitles the Group and/or an individual member of the Workgroup to put forward a Workgroup Alternative Code Modification proposal if the member(s) genuinely believes the alternative proposal compared with the Modification Proposal or the current version of the Grid Code better facilitates the Grid Code objectives The extent of the support for the Modification Proposal or any Workgroup Alternative Modification (WACM) proposal WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the Grid Code Review Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACM proposals as possible. All new alternative proposals need to be proposed using the Alternative request Proposal form ensuring a reliable source of information for the Workgroup, Panel, Industry participants and the Authority.

9. All WACM proposals should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACM proposals which are proposed by the entire Workgroup or subset of members.

10. There is an option for the Workgroup to undertake a period of Consultation in accordance with Grid Code GR. 20.11, if defined within the timetable agreed by the Grid Code Panel. Should the Workgroup determine that they see the benefit in a Workgroup Consultation being issued they can recommend this to the Grid Code Review Panel to consider.

11. Following the Consultation period the Workgroup is required to consider all responses including any Workgroup Consultation Alternative Requests. In undertaking an assessment of any Workgroup Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Grid Code Objectives than the current version of the Grid Code.

12. As appropriate, the Workgroup will be required to undertake any further analysis and update the appropriate sections of the original Modification Proposal and/or WACM proposals (Workgroup members cannot amend the original text submitted by the Proposer of the modification) All responses including any Workgroup Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised their right under the Grid Code to progress a Workgroup Consultation Alternative Request or a WACM proposal against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the Workgroup Consultation Alternative Request.

13. The Workgroup is to submit its final report to the Modifications Panel Secretary on 7 November 2017 for circulation to Panel Members. The final report conclusions will be presented to the Grid Code Review Panel meeting on 15 November 2017.

Membership

It is recommended that the Workgroup has the following members:

Role	Name	Representing (User nominated)
Chair	John Martin	Code Administrator
Technical Secretary	Chrissie Brown	Code Administrator
National Grid Representative*	Richard Woodward	National Grid Electricity Transmission
Industry Representative*	Gregory Middleton	Deep Sea Plc
	David Spillet	Energy Networks Association
	Alastair Frew	Scottish Power
	Paul Youngman	Drax Power
	Peter Thomas	Nordex
	Graeme Vincent	Scottish Power Energy Networks
	Sridhar Sahukari	DONG
	Andrew Vaudin	EDF Energy
	Christopher Smith	National Grid Ventures
	Alan Creighton	Northern Power Grid
	Marko Grizelj/ Chandu Bapatu	Siemens
	Hayden Scott-Dye	Tidal Lagoon Power
	Rui Rui	Scottish Power
	Paul Graham	UK Power Reserve
	Peter Bolitho	Waterswye
	Mick Barlow	S & C
	Tim Ellingham/ Peter Woodcock	RWE
	John Parsons	Beama
	Alan Creighton	Northern Powergrid
	Ushe Mupambireyi/ Andejs Svalovs/ Erwann Mauxion	GE
	Mike Kay	ENA(Electricity North West)
	Dave Draper	Horizon Nuclear Power
	Awais Lodhi	Centrica
	Konstantinos Pierros	ENERCON GmbH
	Garth Graham	SSE Generation Ltd
	Chris Marsland	Trade body representative
Authority Representative	Stephen Perry	Ofgem
Observers	Stephen Gannon	Eleclink
	Nicholas Rubin	Elexon
	Michael Carrington	Eirgrid
	Frank Martin	Siemens

14. A (*) Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk(*) in the table above contribute toward the required quorum, determined in accordance with paragraph 15 below.

15. The Grid Code Review Panel must agree a number that will be quorum for each Workgroup meeting. The agreed figure for GC0101 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

16. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM proposal and Workgroup Consultation Alternative Request based on

their assessment of the Proposal(s) against the Grid Code objectives when compared against the current Grid Code baseline.

- Do you support the Original or any of the alternative Proposals?
- Which of the Proposals best facilitates the Grid Code Objectives?

The Workgroup chairman shall not have a vote, casting or otherwise.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

17. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

18. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

19. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

20. The Workgroup membership can be amended from time to time by the Grid Code Review Panel and the Chairman of the Workgroup.

Appendix 1 – Indicative Workgroup Timetable

The following timetable is indicative for GC0101:

Date	Meeting
Workgroup Meeting 1	7 June 2017
Workgroup Meeting 2	6 July 2017
Workgroup Meeting 3	3 August 2017
Workgroup Consultation issued (15 Working days)	TBC August 2017 (Close: September 2017)
Workgroup meeting	September 2017
Workgroup meeting (WACMs and vote)	October 2017
Workgroup Report presented to Panel	7 November 2017 (Panel: 15 November 2017)

Post Workgroup modification process:

Date	Meeting
Code Administration Consultation Report issued to the Industry (15 Working Days)	17 November 2017 (Close: 8 December 2017)
Draft Modification Report issued to Industry and GCRP Panel (5WDs)	11 December 2017 (Close: 18 December 2017)
Draft Final Modification Report presented to Panel	12 December 2017
Modification Panel Recommendation Vote (5 WDs for Panel comment)	20 December 2017
Final Modification Report submitted to the Authority	10 January 2018
Authority Decision (25WDs)	14 February 2018
Implementation	1 March 2018

Annex 2 – GC0048 Voltage & Reactive; GC0087 RfG Frequency Consultation Responses

GC0048 Voltage / Reactive Consultation Responses

	RESPONDENT	COMMENTS	NATIONAL GRID RESPONSE
1	**EDF ENERGY**	**Supportive** Notes Banding is still an issue but agrees this will be addressed by separate consultation	Comments on Banding noted which will be picked up via a separate consultation
2	**UK PN**	**Supportive** Concerned over omitting Reactive Power and Power Factor Control from Band C requirements if the lower Banding Threshold (B/C – 10MW) is selected. These requirements should be stipulated in the codes rather than via bespoke connection arrangements Suggests overall co-ordiantion (especially G99/G98) with other EU codes before a final decision is made.	It is recognised that the default requirement is voltage control for Type C Power Generating Modules (both Synchronous and Power Park Modules). The current drafting under ECC.6.3.8.3.4 does permit Reactive Power or Power Factor control though this does refer to the Connection Agreement. We do not believe anything is omitted from Band C irrespective of where the boundary is. Agree that overall co-ordination (G99/G98) is required before a final decision is made
3	**AMPS**	**Supportive** Wider issues on fault ride through and banding will be addressed via separate consultation	Comments on Banding and fault ride through noted which will be picked up via a separate consultation.
4	**SSE Generation**	**Supportive** Do not believe that Reactive Power Control can be justified for Type B Generators Requirements are dependent upon Banding – particularly Band B/C. If the lower banding threshold is selected (B/C – 10MW) it is harder to see the justification for the same excitation performance requirements as a large directly connected 660MW Generator	Under the Grid Code, the default performance requirement would be voltage control. For DNO connected Generators, it is expected that voltage control or Power Factor control would be the most likely, with few cases emerging where Reactive Power Control would be likely. For Band C Generators there are some simplifications that can be made to the performance of the excitation system – for example the removal of the need for a Power System Stabiliser which it is acknowledged could add significant cost to the commissioning of the plant. This change will be made to the legal text. In terms of

			lower spec excitation systems tor Type C Synchronous Power Generating Modules, it is believed there is flexibility in the current drafting to permit low spec excitation systems –eg a rotating excitation system rather than static. We will however look at this section to see what further simplifications can be made.
5	**DONG Energy**	**Supportive other than in respect of Offshore Connections** Significant concerns over the interpretation of the voltage / reactive capability for Offshore wind farms (particularly configuration 1) Not comfortable with the use of a Commercial Agreement. Would prefer the use of a Bilateral Arrangement as currently drafted in the GB Code in addition to a Cost Benefit Analysis.	Having re-examined RfG, the Offshore Connection Point of an AC Connected Offshore Power Park Module shall be defined by the Relevant System Operator. The current Grid Code (Under the Offshore Transmission Regime)- states this can be any point between the HV and LV side of the Offshore Platform so it should be possible this could be accommodated going forward. Art 25(5) states that for a Configuration 1 Offshore wind farm the maximum Q/Pmax value is 0 (ie unity power factor). Art 21(3)(b) states the U-Q/Pmax profile shall not exceed the U-Q/Pmax profile represented by the inner envelope of Figure 8 and the dimensions of the U-Q/Pmax profile (Q/Pmax range and voltage range) shall be within the values specified for each synchronous area (ie Table 11 for Offshore Power Park Modules) – The wording in RfG is unclear, as it implies that a wider range cannot exceed the maximum in Table 11. We agree that this value in unduly restrictive as highlighted in section 10.17 of the consultation document. We fully agree with your response in relation to this issue as we see no reason why a wider capability could not be accommodated especially as there are significant benefits to utilizing the capability of the turbines. We will seek clarity on this issue with ENTSO-E and if they are agreeable to our proposal, one option would be to require Configuration 1 AC connected Offshore wind farms to meet the minimum requirements of Art25(5) but that would not preclude them from satisfying a wider reactive capability range if agreed between the OFTO, Offshore Generator and National Grid This approach would remove any reference or need for a Commercial Agreement and would bring the proposal more in line with current GB

			Grid Code practice the approach for a wider range as agreed between all parties would be subject to a positive cost benefit analysis. In terms of reactive capability, it is assumed that the reactive capability requirements would be specified at the Offshore Grid Entry Point although we recognise the flexibility under Article 21(3)(a) of RfG. Pending the response of ENTSO-E it is proposed the legal text is updated to reflect the above comments.
6	**ScottishPower Renewables**	**Supportive** SPR disagree on Question (vi) that historically the requirements in the Distribution Code are generally less onerous than those in Grid Code making distribution connections cheaper	For Type C and D Power Generating Modules there should be little difference between the reactive capability and control performance requirements between Distribution and Transmission Connected Generators. That said it is acknowledged that RfG gives little guidance in respect of the excitation performance requirements for Type C Synchronous Power Generating Modules. The current proposal is for Type C Synchronous Power Generating Modules to have the same requirements as Type D Synchronous Power Generating Modules, although based on the comments from this consultation, a suggestion would be for Type C Synchronous Power Generating Modules not to be required to have a Power System Stabiliser. For Type C and D Power Park Modules the control system specification (ie voltage control, power factor control or reactive power control) would be at the discretion of the System Operator (in co-ordination with the relevant TSO. Since the Relevant System Operator could be the Transmission System Operator or Distribution Network Operator then it is possible that the requirements could be different between the Transmission or Distribution System. For Type B Generators , RfG is very vague leaving the requirements for Excitation and control performance to the discretion of the Relevant System Operator (ie the

			Transmission System Operator or Distribution Network Operator). It is acknowledged that at a site specific level, the Distribution connection requirements could be less onerous than the Transmission connection requirements however it needs to be re-emphasised that so far as RfG is concerned, they are the same.
7	**RWE**	**Not Supportive unless detailed comments are addressed**	
		Definition of Performance chart at the terminals and at the Connection Point	Agreed – Text will be updated to make this more explicit
		ECC.6.3.2.4 – Minimum Generation should be used rather than DMOL	We think it may be better to retain the existing GB definition of DMOL. We recognise that RfG uses the term “Minimum Regulating Level” but to maintain consistency and avoid over complexity in the code (as the term DMOL) is still likely to be used going forward, we feel it would be better to retain the GB term. DMOL is the output below which a Genset or DC Converter has no high frequency response capability. Minimum Regulating level is specified in the connection agreement down to which the power generating module can control active power. In summary it may be required to change the definition of DMOL to include elements of minimum regulating level but we will continue to review this.
		ECC.6.1.4 – 400kV operating range -5% to +10%. This needs to be made consistent with Art 16(2)	Agreed – the text will be updated to ensure consistency with RfG.
		Figures X3 – X6 - Q/Pmax is used rather than Power Factor. The Grid Code should contain one consistent term throughout	Agreed – Text will be updated to make this more explicit

		Rated MW is not an RfG term and should be replaced by Maximum Capacity	It is acknowledged that Maximum Capacity (in the majority of cases) is the correct term from a connections requirement perspective, though a consistency check needs to be made to ensure that the correct terms have been used in the legal text. However the term Rated MW will still be required largely for data submission purposes.
		The new drafting makes no reference to reactive capability above Rated MW which is currently covered in the existing GB Code	Under RfG, the reactive capability requirement is at the Connection Point not at the terminals of the alternator. The reactive capability is therefore a function of Maximum Capacity which are both quantities with respect to the Connection Point. We therefore believe that operation above Rated MW is not relevant in an RfG world.
		ECC.6.3.4.1 – Concern that changes to ECC.6.1.4 make the requirement to maintain constant Active Power more demanding	This is largely a copy of the existing GB Grid Code text as is ECC.6.1.4 so it is unclear why this requirement would be more onerous. Under the current GB Grid Code, the requirement for voltage range defined under CC.6.1.4 states the 400kV voltage will normally remain within ±5% unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail.
		ECC.6.3.8.3.3 – Maximum upper limit on terminal voltage to be specified.	This is largely a copy of the existing GB Grid Code text which was introduced following Grid Code consultation GC0028. At that time no maximum limit was placed on terminal voltage as it was felt that this value would be determined by the Generator in the interests of protecting their Plant and Apparatus. It is however a data value required to be submitted by Generators under PC.A.5.3.2(a).

		ECC.6.3.12.1.1 – Concerns over combines voltage / frequency ranges and the costs to which Generators could be exposed.	This issue was previously raised as part of Grid Code Consultation D/10 (Frequency and Voltage operating ranges). It is not clear that RfG changes this position. In fact it is probably worth noting that this clause introduces greater flexibility than in the current GB Grid Code.
		Concern that a PSS is required for Type C Synchronous Power Generating Modules	We agree with this comment. For Type C Synchronous Power Generating Modules we would not mandate the need for a Power System Stabiliser, however we do need to ensure that any Synchronous Generating Unit connected to the Network displays an adequate level of damping so we can comply with the requirements of the SQSS.
		Voltage control preferred for Type B Generators. Recognised that there may be many transformation levels between a Type B Generator connected to an industrial network and the transmission network or a Type B Generator connected directly to the Transmission System	Point noted
8	**SP Energy Networks**	**Supportive** Banding needs to be addressed Voltage / Reactive Requirements need to be assessed by the SO and DNO on a site specific basis Noted that there are and will be numerous connections in Scotland at 33kV which are Transmission connected. Need to fully review the glossary and definitions to ensure consistency across the codes.	Banding will be addressed via a separate consultation which will need to take a number of technical issues (including voltage / reactive into account). As far as RfG is concerned, the requirements for reactive capability and control are the same however it is noted that the detailed performance requirements will need to vary depending on connection point, topology and Network operator requirements. Typographical errors noted in Para 8.16, and that there will be cases of direct connections at 33kV. A full review of all the definitions will need to be undertaken when all the EU code mods are more advanced.

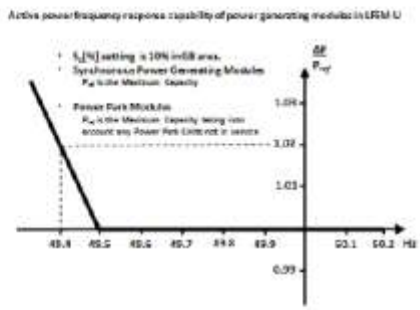
9	**NPG**	**Supportive** If the lower Banding threshold (10MW) is selected, should Type C be included in G99 Definitions need to be consistent across the Codes ECC.6.1.4 – 132kV is not a Transmission Voltage in England and Wales – clarification of 110kV required ECC.6.3.1.1 – The Grid Code needs to be clear that for any plant which is embedded the requirements of the Distribution Code would also apply ECC.6.3.2.6.2 3&4 – Confusion between the way in which reactive power is defined Comments on G99 drafting – ECC.6.3.8.1&2/ECC.A.7.3&4 – If Type B Generators are independent of whether they are distribution or transmission connected should the text be replicated in G99 Oc2.4.2- G99 to consider the need for an operating chart at the alternator terminals and connection point	See last paragraph below ECC.6.1.4 is largely a direct lift from the GB Grid Code which includes voltages less than 132kV. In addition there will be cases where TO's own network less than 132kV so the Grid Code will need to cover these aspects. ECC.6.3.1.1 – Agreed – the text will be updated to address this issue. ECC.6.3.2.6.2 3&4 - Agreed – the text will be updated to address this issue. The working assumption is that embedded Type C and D will be coded in the Grid Code with a reference to that from the D Code. However this needs a thorough debate when the implications of this become clearer. It is proposed for the time being to carry on on this route, and when the drafting is fairly complete, and all the obligations etc clearly laid out in drafting, it will be easier to see how proposals to put Type C obligations in the D Code will work, and being able to be sure that the complete implications are observable.
10	**Siemens**	**Supportive other than in respect of Offshore Connections** Significant concerns over the interpretation of the voltage / reactive capability for Offshore wind farms. Not comfortable with the use of a Commercial Agreement. Would prefer the use of the flexibility as currently drafted in the GB Code plus a Cost Benefit Analysis.	Similar issues as per item 5 above –DONG Energy
11	**SSEN**	**Supportive** Comments noted on Banding G99 Comments – 50kW Split between G99 and G98 however a better solution may be to have a boundary at the connection	Any Report to the Authority or revised consultation document would need to highlight the following points:- Banding is still unclear The large volumes of embedded generation initially seen in Scotland now apply

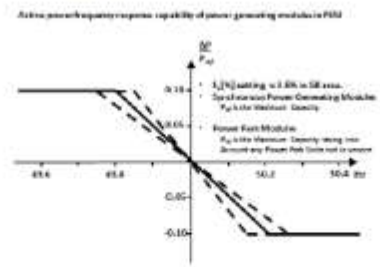
		voltage (ie the LV connection with an upper limit of 1MW matching the requirements in RfG. How will a power station comprising synchronous and asynchronous generators be dealt with	across large parts of England and Wales. A regional variation in Scotland is therefore not applicable. Appropriate control (eg voltage control, reactive power control, or Power Factor control) already apply to Type B Synchronous Generators and to some Type A Power Generating Modules (ie both Synchronous and Asynchronous) Split Band A - Consideration to be given to splitting the documentation – For further consideration in the near future. Operational aspects of G98 and G99 will need to be considered in the fullness of time but this issue can be dealt with in the future. How would a power station be treated which comprised of synchronous and a synchronous units. An example of this could be included in the Report to the Authority.
12	**ScottishPower Generation**	**Supportive** Concern over definitions in particular physical quantities such as current, voltage etc	In developing the Grid Code legal text, it has been assumed that we will retain GB definitions where possible and only use European definitions where there is a need to do so. The issue of physical quantities was raised on a number of occasions and that a pragmatic approach developed. The principle adopted is that physical quantities such as voltage and current are not defined in the GB Grid Code. It is proposed that this approach is retained so that when terms such as voltage and current are used in the GB code they are not defined, the intention being that the term current or voltage is then used in the appropriate context.

GC0087 – RfG Frequency Consultation Responses

	RESPONDENT	COMMENTS	NATIONAL GRID RESPONSE	UPDATED NATIONAL GRID RESPONSE
1	**EDF ENERGY**	**Supportive with the following note:** We agree with the reasoning behind the value of 1 Hz/sec. to be set as a RoCoF Withstand capability limit, as per RFG Article 13.1 (b). However, we would also expect an appropriate level of transparency and process to be in place governing the associated RoCoF Operational limit. The RoCoF Operational limit is an internal National Grid limit currently set at 0.125 Hz/sec. We believe that it would be more appropriate for this limit to be included in the SQSS, where the Operational limit set value would be visible, and where there is a modification process in place. Such an approach would be in line with other operational standards and, given the importance of the RoCoF issue and the fact that it is already an active operational consideration, would give the right emphasis to this key parameter.	National Grid does not believe a RoCoF limit specified within the SQSS is necessary or beneficial. The necessity of managing RoCoF arises from the requirement to ensure that there are no "Unacceptable Frequency Conditions" prior to any fault or following a secured event. Hence, NGET ensures that the RoCoF stays below the limit that would result in any loss of generation. At the moment, NGET uses a RoCoF limit of 0.125Hz/s. This is dictated by the LoM protection settings of embedded generation. Once the settings of existing relays have all been revised to be 1Hz/s, NGET will work to the new limits. Exceeding these limits would result in large loss of infeed that the system is not likely to be able to cope with. Hence the value that NGET is required to manage RoCoF to is implicit. If we set a RoCoF limit in the SQSS at the current 0.125Hz/s limit, then we have to	No change to original response

			manage RoCoF to that level even after revising the settings for all existing RoCoF. If we set a RoCoF limit in the SQSS at the future 1Hz/s limit, then we would not be able to manage it to the 0.125Hz/s. This means that the RoCoF limits would contradict the frequency control limits. The process of managing an SQSS modification to change RoCoF from 0.125Hz/s to 1Hz/s in coordination with the programme to revise the settings for all the relays would be challenging. Hence, the view is that acceptable RoCoF limit is implicitly specified as the level that would not result in generation loss. This provides the flexibility required to be economic and efficient and is transparent. The RoCoF withstand limit was set at 1Hz/s for the purposes of informing manufacturers of the new design specification requirements.	
2	**Nordex**	**Supportive with the following exception** Further clarification is sought on the proposed modifications to ECC6.3.7.3.1, ECC6.3.7.2.2 and ECC6.3.7.3.3 as this is contrary to industries understanding.	This section of code resulted from lengthy and vigorous negotiations between NG and the GB wind industry (including representatives from wind farm manufacturers) during the H/04 grid code	No change to orginal response. However the legal text will be updated to clarify the droop requirements for

		ECC6.3.7.3.1 In addition to the requirements of ECC6.3.7.1 and ECC6.3.7.: **Power Generating Module** must be fitted with a fast acting pro device (or turbine speed governor) and unit load controller or provide **Frequency** response under normal operational con **Balancing Code 3** (BC3). In the case of a **Power Park Modul** control device(s) may be on the **Power Park Module** or on each or be a combination of both. The **Frequency** control device(s) be designed and operated to the appropriate: ECC6.3.7.2.2 (vi)  Figure X2 – Pref is the reference **Active Power** to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the frequency deviation in the network. At underfrequencies where Δf is below Δf₁ the **Power Generating Module** has to provide a positive **Active Power** output change according to droop S₂ which shall be no greater than 10%. The figure X2 has a small note stating that the response for a power park module is based upon the number of power park units in service.	modification process. This negotiated agreement resulted in freedom for wind farm operators and OEMs to choose central or power park unit based frequency response control systems. The existing grid code text ensures that as the number of PP Units in a PPM reduces, the duty required of the remaining PP Units does not increase. Many operators and OEMs would see this as an advantage. Many wind turbine manufacturers and wind farm controller suppliers have already produced systems which comply with the GB Grid Code which allows a reduction in response as the number of available PP Units reduces. Therefore a grid code amendment to address the challenges identified by Nordex could require modification to these systems and this would probably be unwelcome by many GB wind farm owners. Response to comment on ECC6.3.7.3.3. (vii), Current GB Grid Code does not define	Synchronous Power Generating Modules and Power Park Modules which are proposed to be based on Maximum Capacity rather then Output. This is a capability requirement and the performance requirement would be adjusted depending upon the amount of turbines in service.

		ECC6.3.7.3.3 **Type C** and **Type D Power Generating Modules** shall also meet the following minimum requirements: (i) **Power Generating Modules** shall be capable of providing **Active Power Frequency** response in accordance with the performance characteristic shown in Figure X3 and parameters in Table X1.  Figure X3 – P_{ref} is the reference **Active Power** to which ΔP is related. ΔP is the change in **Active Power** output from the **Power Generating Module**. f_n is the nominal **Frequency** (50Hz) in the **System** and Δf is the frequency deviation in the **System**. Figure X3 illustrates the case of zero **Deadband** and **Insensitivity** (ii) In satisfying the performance requirements specified in ECC6.3.7.3(i) **Generators** in respect of each **Type C** and **Type D Power Generating Module** should be aware:- in the case of overfrequency, the **Active Power Frequency** response is limited by the **Minimum Regulating Level**. in the case of underfrequency, the **Active Power Frequency** response is limited by the **Registered Maximum Capacity**, the actual delivery of **Active Power** frequency response depends on the operating and ambient conditions of the **Power Generating Module** when this response is triggered, in particular limitations on operation near **Maximum Capacity** at low **Frequencies** as specified in ECC6.3.3 and available primary energy sources The frequency control device (or speed governor) must also be capable of being set so that it operates with an overall speed **Droop** of between 3 – 5%. The deadband and droop must be able to be reselected repeatedly. For the avoidance of doubt, in the case of a **Power Park Module** the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service. The figure X3 has a small note stating that the response for a power park module is based upon the number of power park units in service. Windfarm manufacturers believed the windfarm	this.	

		operators and OEM's had the freedom to choose central or power park unit based frequency response (ECC6.3.7.3.1) With the advantage that a module approach would give the response based upon the available active power in the wind regardless of the unit available and not the number of WTG's in service. The unit approach enables the windfarm to decrease the power output when units are out of service. Now however it appears in the figures that there is no distinguishing between either approach. If it were treated as a module with a central controller the windfarm must de-rate the remaining available power to represent the loss of a unit in service. Finally The module approach has significant available capacity advantages over most of the operating range. Which would (with the Unit approach) have to be supplied by conventional or legacy generation, at extra cost. Surely there is a cost benefit advantage from the module approach to National Grid, should it be available. Also one comment on ECC6.3.7.3.3. (vii) ECC.6.3.7.3.3		

		(vii) Where a **Type C** or **Type D Power Generating Module** becomes isolated from the rest of the **Total System** but is still supplying **Customers**, the **Frequency** control device (or speed Governor) must also be able to control **System Frequency** below 52Hz unless this causes the **Type C** or **Type D Power Generating Module** to operate below its **Designed Minimum Operating Level** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt the **Power Generating Module** is only required to operate within the **System Frequency** range 47 - 52 Hz as defined in ECC6.1.3 and for converter based technologies, the remaining island contains sufficient fault level for effective commutation; The ESQ&C (Electrical Safety, Quality and Continuity regulations 2002) in particular requires Islanded systems to be earthed at one point. The present text has no reference to this Statutory regulation. A reference to this should be included here for information.		
3	**Britned**	**Unsupportive** Based on the Grid Code drafting provided, it is difficult to understand how the impact on Interconnectors/DC Converters has been assessed at high. The Grid Code drafting is unclear and incomplete for DC Converters which makes assessment of the impacts impossible. Below are our comments Definitions • The proposed change to 'Genset' to include BM Participant means that it would capture DC Converters. This doesn't appear to be the intention as ECC.6.3.1.2 indicates that requirements for DC Convertors are contained elsewhere. If the intention is to capture DC Converters with 'Genset' has the Grid Code been reviewed for the consequential impacts this definition change cause?	GC0087 was part of the EU Requirement for Generators and was not intended for HVDC connections, these were being covered under GC0090 workgroup. Both the RfG and HVDC Codes do not apply to existing Generators or HVDC Converters. An existing Generator/HVDC Converter is one which is already running / commissioning or has not let its contract for major plant items (eg turbine, Generator, converter equipment etc) from two years after Entry into force) of the Codes. For RfG the Entry into Force Date was 17th May 2016 and for HVDC the Entry into Force Date was 29th September 2016. HVDC requirements have been included	Legal text updated toi include HVDC Converters

		• 'HVDC Systems' referred to in ECC.6.3.1.2 is not defined. How does this differ from DC Converters? • 'Type A, Type B, Type C and Type D Power Generating Modules' referred to in ECC.6.3.1.1 and throughout the drafting are not defined. It is assumed that DC Converters are not captured by any of these definitions (specifically Type D) but a definition that makes this clear would be useful. ECC.6.3.1.2 • This clause is incomplete and makes it impossible to assess the impact on DC Converters. Applicability • Paragraphs 2.8 and 2.9 of the consultation indicate when these requirements will be applicable but the Grid Code text is unclear. A clearly identified date of when the requirements will be applicable is suggested as this clarifies any issues around retrospective application and enables parties to better understand	in GC0101 text.	
4	**Scottish Power Renewables**	**Supportive with the following comments** 1. Page 54 - ECC.6.3.X.1 is the input port receiving a digital or analogue signal? SPR believes that this type of technical considerations should be taken into account before including the input port requirement in the grid code. As an example there was widespread confusion on the Power available signal and to date transmission licensee as SPT does not include in the exchange signal list Power available	1. This can be defined 2. This can also be defined 3. Disagree, this is an RfG requirement 4. This can be defined 5. Asynchronous generators or any generator connected via power electronic equipment are defined as	~~6.~~ The legal text has been updated to address the majority of these issues.

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		2. Page 57- ECC.6.3.7.1.2 States the minimum droop requirement for LFSM-O shall be no greater than 10% SPR believes that as this is the minimum requirement there should be a clarification as if a droop between 3% to 5% (and any droop between 5% and 10%?) is acceptable as this can greatly simplify the frequency response controller logic 3. Page 59 - ECC.6.3.7.2.1 The word "not mandatory" shall be included in the text of this clause for LFSM-U 4. Page 59 - ECC.6.3.7.2.2. Same comment as item 2 above. 5. Page 63 – Table X4. SPR believes that there should be a value of inertia that defines what generators are considered to not have inertia as some renewable energy generators could have very little inertia. Without a limit value of inertia the interpretation of generators without inertia is ambiguous otherwise a system with very low inertia can be considered compliant with an initial time delay of 2s?	not having inertia	

Annex 3 – Grid Code Draft Legal Text

The legal text will be developed by the Workgroup after the Workgroup Consultation but a draft of what the changes may encompass are included below for information.

Annex 4 – Distribution Code Draft Legal Text

The legal text will be developed by the Workgroup after the Workgroup Consultation but a draft of what the changes may encompass are included below for information.

Annex 5 – Remote end HVDC Converter Frequency Response paramters Title III

GB FREQUENCY HVDC FREQUENCY RESPONSE PARAMETERS
REMOTE END HVDC CONVERTERS (TITLE III)

HVDC Article	Requirement	Range	Suggested GB Value	Comments	Policy Req'd? (e.g. Non-compatibility to be defined)	Code Change req'd?
46	All Frequency related aspects eg Frequency Range, LFSM, FSM, Active Power Controlability	As per HVDC Interconnectors – Title II				
47(1)	Frequency communication Signals and co-ordianiton	Specified by TSO	As per DC Connected PPM's	Amend CC.6.3.3 and CC.6.3.6	No	Yes

Annex 6 – HVDC Frequency Response Paramters Title II

GB FREQUENCY HVDC FREQUENCY RESPONSE PARAMTERS
HVDC CONNECTIONS (TITLE II)

HVDC Article	Requirement	Range		Suggested GB Value		Comments	Policy Req'd? (e.g. Non-compatibility to be defined)	Code Change req'd?
11	Frequency Range	47 – 47.5Hz	60 seconds	47 – 47.5Hz	60 seconds	Mandatory requirement	?	Yes
		47.5 – 48.5Hz	TSO defined (but longer than RfG and DCC and DC PPm's (ie 90 minutes plus)	47.5 – 48.5Hz	100 minutes	Wider ranges and longer minimum operating times may be agreed Work group to discuss	?	Yes
		48.5 – 49.0Hz	TSO defined (but longer than RfG and DCC and DC PPm's (ie 90 minutes plus)	48.5 – 49.0Hz	100 minutes	Wider ranges and longer minimum operating times may be agreed Work group to discuss	?	Yes
		49.0 – 51.0 Hz	Unlimited	49.0 – 51.0 Hz	Unlimited	As per GB Code		No
		51.0 – 51.5Hz	TSO defined (but longer than RfG and DCC and DC PPm's (ie 90 minutes plus)	51.0 – 51.5Hz	100 minutes	Wider ranges and longer minimum operating times may be agreed Work group to discuss	?	Yes
		51.5Hz - 52	TSO defined (but longer	51.5Hz - 52	20minutes	Wider ranges and longer	?	Yes

			than DC PPm's (ie 15 minutes plus)			minimum operating times may be agreed Work group to discuss		
12	ROCOF	-2.5 to +2.5Hz/s	Measured over the previous 1 second	-2.5 to +2.5Hz/s	Measured over the previous 1 second	Mandatory requirement	?	Yes
13(1)(a)(i)	Active Power Controlability Maximum and Minimum Power Step Size for Transmitting Active Power	TSO specified		Max Step Size = 1MW Min Step Size = 1MW		Workgroup to discuss MW transfer should be controllable to the nearest whole MW	?	Yes
13(1)(a)(ii)	Minimum HVDC Active Power Transmission capacity for each direction below which active power transmission is not requested	TSO specified		Workgroup to discuss – believed to be part of data submission as part of trading in wholesale market / TSOG?		Workgroup to discuss MW transfer should be controllable to the nearest whole MW	?	Yes
13(1)(a)(iii)	The maximum delay within which the	TSO specified		2 minutes – as per BC2		Workgroup to agree	No	No

	HVDC System shall be capable of adjusting the transmitted active power upon receipt of request from the relevant TSO					
13(1)(b)	Capability of modifying transmitted Active Power infeed in case of disturbances into one or more AC networks	TSO specified	Covered by Fault Ride Through – additional text to be added for HVDC and delays greater than 10ms	Workgroup to agree	Yes	Yes
13(1)(c)	Active Power Reversal	TSO specified	Would be required only on a site specific basis and would be specified in the Bilateral Agreement. General Grid Code Mod to refer to the requirement and time delay	Workgroup to agree	?	Yes – General words required in relation to Power Reversal
13(1)(d)	Ability to modify transmitted active power for the purpose of cross boarder balancing	Not specified	Covered by CC.6.3.7 through the requirement to have a load controller and the Balancing Codes	Workgroup to agree	No	No?

13(2)	Ramp Rate Limit adjustment	Not specified		Ramp Rate Limits covered under BC1.A.1.1 Adjustment of Ramp Rates below the limits of BC1.A.1.1 are permissible – see BC1			No	No
13(3)	Automatic Remedial Action	TSO specified		Other than the current requirements under the Balancing Codes any other requirements would be specified under the Bilateral Agreement			No	Yes – Only by reference to additional requirements being specified in the Bilateral
14	Synthetic Inertia	TSO specified		Not required – see FFCI requirements Option 1			No	No
15	FSM, LFSM-O, LFSM-U							
Annex II(A)(1)	FSM	Deadband	0 ±500mHz	Deadband	0	As per RfG See Insensitivity	No	No
		Droop S1(u)	Minimum 0.1%	DroopS1 (u)	3 – 5%	As per current Grid Code	No	No
		Droop S2(d)	Minimum 0.1%	DroopS2 (d)	3 – 5%	As per current Grid Code for upward regulation	No	Yes – Current Grid Code does not make this clear
		Insensitivity	Maximum 30mHz	Insensitivity	15mHz	As per current Grid Code for Deadband	No	Yes – Introduce term insensitivity as per RfG
Annex II(A)(1)(d)		Maximum admissible	0.5 seconds	Maximum admissible	0.5 seconds	RfG for non synchronous	Yes	Yes

		delay t1		delay t1		plant set to 1s		
		Maximum admissible activation Time t2	30 seconds	Maximum admissible activation Time t2	10 seconds	As per RfG and current Grid Code practice	No	No
Annex II(B)(1)	LFSM-O	Frequency Threshold f1	50.2 – 50.5Hz	Frequency Threshold f1	50.4Hz	As per current Grid Code	No	No
		Droop S3	0.1% upwards	Droop S2	10% or less	As per current Grid Code	No	No
		Initial activation time	TSO specified	Initial activation time	<2s	As per RfG	No	Yes
		Full activation time	TSO specified	Full activation time	10s	As per current Grid Code	No	Yes
Annex II(c)(1)	LFSM-U	Frequency Threshold f2	49.8 – 49.5Hz	Frequency Threshold f2	49.5Hz	As per current RfG	No	Yes
		Droop S4	0.1% upwards	Droop S4	10%	As per RfG	No	Yes
		Initial activation time	TSO specified	Initial activation time	<2s	As per RfG	No	Yes
		Full activation time	TSO specified	Full activation time	To be determined – plant Dependent	Discuss with Working Group	Yes	Yes
16	Frequency Control	Modulation of Active Power in relation to Frequency	TSO specified	Modulation of Active Power in relation to Frequency	As per CC.6.3.6 of Grid Code	Discuss with Working Group	No	No

		Changes		Changes				
17	Maximum Loss of Active Power	TSO specified		Loss of Active Power	1800MW	As per SQSS discuss with Workgroup	No	No
37	Black Start	TSO specified		Black Start	Specified in Bilateral Agreement in the same way as Generation	As per current Grid Code and Bilateral Agreement	No	No

Annex 7– DC Connected Power Park Modules Frequency Response paramters Title III

GB FREQUENCY HVDC FREQUENCY RESPONSE PARAMETERS
DC CONNECTED POWER PARK MODULES (TITLE III)

HVDC Article	Requirement	Range		Suggested GB Value		Comments	Policy Req'd? (e.g. Non-compatibility to be defined)	Code Change req'd?
38	All Frequency related aspects eg Frequency Range, LFSM, FSM, Active Power Controlability	As per RfG unless stipulated below						
39(1)	Frequency communication Signals and co-ordianiton	100ms signaling and processing time required Co-ordination between control areas required		Mandatory requirement		Amend CC.6.3.3 and CC.6.3.6	No	Yes
39(2)(a) Annex VI	Frequency Range	47 – 47.5Hz	20 seconds	47 – 47.5Hz	20 seconds	As per RfG	TSO values to be specified where the nominal frequency is not 50Hz	No
		47.5 – 49Hz	90 minutes	47.5 – 49 Hz	90 minutes	As per RfG		No
		49.0 – 51.0 Hz	Unlimited	49.0 – 51.0 Hz	Unlimited	As per GB Code		No
		51.0 – 51.5Hz	90 minutes	51.0 – 51.5Hz	90 minutes	As per RfG		No
		51.5Hz - 52	15 minutes	51.5Hz - 52	15 minutes	As per RfG		No
39(2)(b)	Wider Frequency ranges / operating times	Specified by TSO – as per RfG						

39(2)(c)	Automatic Disconnection at specified frequencies	Specified by TSO – as per RfG						
39(3)	ROCOF	-2.0Hz/s to +2.0Hz/s	Measured over the previous 1 second	-2.0Hz/s to +2.0Hz/s	Measured over the previous 1 second	Mandatory requirement	?	Yes
39(4) – 39(9)	LFSM-O, Output Power with Falling Frequency, Active Power Controlability, LFSM-U, FSM, Frequency Restoration	As per PPM RfG settings						
39(10)	DC Connected PPM's connected to AC systems with frequencies other than 50Hz	Specified by TSO – would be included in Bilateral Agreement and treated as new and emerging technology						