Grid Code Modification Proposal Form	At what stage is this document in the process?
# GC0111: ## Mod Title: Fast Fault Current Injection specification text	01 Proposal Form **02 Workgroup Report** 03 Code Administrator Consultation 04 Draft Grid Code Modification Report 05 Final Grid Code Modification Report

Purpose of Modification: To update the Grid Code and G99 with revised text for fast fault current injection to dispel any confusion in interpretation of the existing text.

✔	This document contains the discussion of the Workgroup which formed in July 2018 to develop and assess the proposal, the voting of the Workgroup held on [Date] and the Workgroup's final conclusions.
!	**High Impact**: None
!	**Medium Impact**: Manufacturers, installers and owners of Type B to Type D power park modules connected to both distribution and transmission systems
!	**Low Impact** None

Contents

Timetable

The Code Administrator recommends the following timetable:

Initial consideration by Workgroup	4 July 2018
Modification concluded by Workgroup	February 2019
Workgroup Report presented to Panel	28 February 2019
Code Administration Consultation Report issued to the Industry	w/c 4 March 2019
Draft Final Modification Report presented to Panel	28 March 2019
Modification Panel decision	28 March 2019
Final Modification Report issued the Authority	w/c 1 April 2019
Decision implemented in Grid Code	w/c 13 May 2019

Any questions?

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1 About this document

This document is the Joint Workgroup Report containing the discussion of the Workgroup which formed in July 2018 to develop and assess the proposal and the voting of the Workgroup held on [Date].

GC0111 was proposed by Electricity North West Limited and was submitted to the Grid Code Review Panel for its consideration on 26 April 2018 and to the Distribution Code Review Panel on 5 April 2018. The Panels decided to send the Proposal to a Joint Workgroup to be developed and assessed against the Grid Code and Distribution Applicable Objectives.

GC0111 aims to amend the Grid Code and Distribution Code (actually to EREC G99) to provide revised text in relation to fast fault current injection to dispel any confusion in relation to the existing text within the Grid Code and EREC G99.

Workgroup Conclusions

At the final Workgroup meeting, Workgroup members voted on the Original proposal. [Insert number of WG members] members voted that the Original Proposal better facilitated the applicable Grid Code objectives.

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 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The Grid and Distribution Code Review Panels detailed in the Terms of Reference the scope of work for the GC0111 Workgroup and the specific areas that the Workgroup should consider.

The table below details these specific areas and where the Workgroup have addressed the Terms of Reference within the report.

The full Terms of Reference can be found in Annex 1.

Table 1: GC0111 Terms of Reference

Specific Area	Location in the report
a) Implementation and costs	Section 3 and 4
b) Review draft legal text should it have been provided. If legal text is not submitted within the Modification Proposal the Workgroup should be instructed to assist in the developing of the legal text.	Section 4 and 8

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. Demonstrate what has been done to cover this clearly in the report*	Section 4
d) Consider materiality of change	Section 4
e) Workgroup consultation and whether required	Section 4
f) Review the trigger voltage and FRT requirements and whether compatible.	Section 4

2 Original Proposal

Defect

The Grid Code and Distribution Code modification being implemented in GC0100 has recast the long-standing Grid Code Fast Fault Current Injection (FFCI) requirements in a way that is phrased so as to be compatible with the Requirements for Generators (RfG). However, the wording chosen is open to misinterpretation and has induced some confusion amongst a small number of stakeholders.

What

The specification and testing requirements for FFCI need to be clarified in the Grid Code – and this clarification fed into G99 which also needs to be updated to reflect this.

Why

Manufacturers of Power Park Modules need clarity on the FFCI requirements so that then can ensure compliance at the point of manufacture. It is not possible to test for compliance with the FFCI requirements on site, so it is crucially important that the requirements are specified with complete clarity and freedom from ambiguity.

How

The Grid Code and Engineering Recommendation (EREC) G99 will need to be modified post clarification of the compliance requirements.

3 Proposer's solution

The requirements for FFCI as specified in ECC 6.3.16.1 and G99 12.6 and 13.6 will need to be updated following agreement in the Workgroup as to the precise requirements that need to be complied with.

In GC0100 new requirements were introduced into the Grid Code in respect of fast fault current injection. These requirements apply only to Power Park Modules. Prior to the introduction of RfG, there was a loose requirement for fast fault current injection although this simply stated that each Power Park Module shall generate maximum reactive current without exceeding the transient rating of the Power Park Module and/or any constituent Power Park Unit. There was no requirement until G0100 for distribution connected Power Park Modules to provide FFCI.

On the other hand RfG (Article 21(3)) specifies a much more detailed requirement with respect to the reactive current injection requirements. These issues and the approach to implementation were covered in consultation GC0100 which is available from the following link.

https://www.nationalgrideso.com/sites/eso/files/documents/Final%20Workgroup%20consultation_0.pdf

Shortly after the consultation, and after the proposals had been submitted to the Authority, a number of comments were received in relation to the clarity over the interpretation of fast fault current injection. These mainly related to the plant rating, how the injected current may vary in phase and magnitude with respect to both voltage deviation and time.

The first meeting was held in July 2018 to articulate the scope of the problem and define that there would be no requirement for the rating of the Power Park Module to be exceeded. The slides for this first meeting are attached in Annex 1. Of importance during this meeting was the introduction of a concept to specify that the rating of the Power Park Module was not expected to be exceeded.

Figure 1.0 below shows a typical wind farm comprising one Power Park Module. Under a faulted condition where the voltage at the connection point falls to zero the intention would be for the Power Park Module to supply full reactive current without the rating of the Power Park Module or HVDC System from being exceeded.

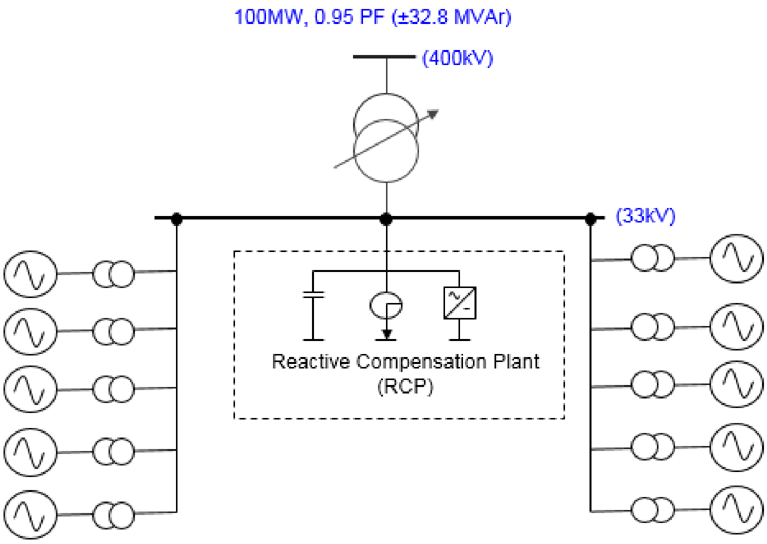

Figure 1.0

The rating of the Power Park Module or HVDC System is calculated on the basis of the rated MW output at maximum Reactive Power Output. Taking the example of the wind farm shown in Figure 1.0 below, if the Rated MW output was 100MW and under ECC.6.3.2.4 the reactive capability requirement is 0.95 Power Factor lead to 0.95 Power Factor lag, which requires a reactive capability of ±32.9MVAr the rating of the Power Park Module becomes 105.3 MVA (ie $\sqrt{(100^2 + 32.9^2)}$ or 1.0pu on Rated MVA (ie 105.3/105.3).

Under a faulted condition, the fall in voltage will result in a consequential increase in reactive current to the point where at zero voltage at the connection point the full reactive current injection. As noted above, the reactive current injection would not be required to exceed the rating of the Power Park Module or HVDC System.

Figure 2.0 below shows how the real and reactive current varies. The locus (ie the circle) being the rating of the Power Park Module or HVDC Converter which in this example is 1.0pu on the MVA base of the Power Park Module or 105MVA.

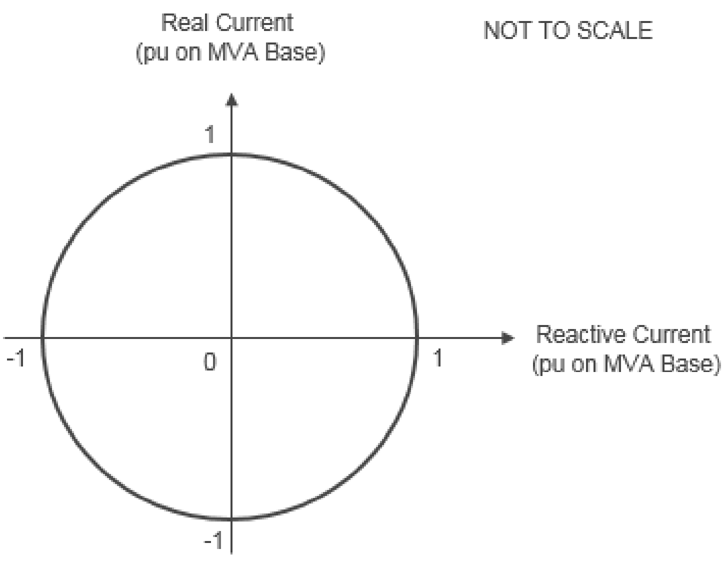

Figure 2.0

In the event of a fault, Figure 3.0 shows the blue vector and blue dashed vector moving towards the x axis (ie an increase in reactive current supply as compared to the red and green vector which forms the boundary between when the Power Park Module is operating in a steady state condition (ie operation between 0.95 lead and 0.95 lag).

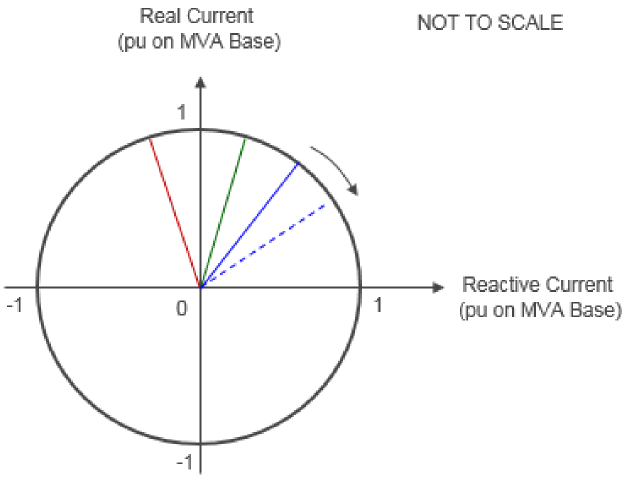

Figure 3.0

The current drafting of ECC.6.3.16 and G99 12.6 and 13.6 does not make this clear. The second deficiency is that it is not clear how the reactive current would vary with depressed voltage.

At its highest level, National Grid has a number of fundamental requirements when it comes to ensuring the robustness of the system under fault conditions. These are summarised as follows:-

Criteria	**Requirement**
Fault Ride Through	Power Generating Modules to remain connected and stable for up to 140ms in duration for both balanced and unbalanced faults which would include a close up solid three phase short circuit adjacent to the Connection Point
	Power Generating Modules to remain connected and stable for any balanced fault in excess of 140ms so long as the retained voltage is above the heavy black line specified in ECC.6.3.15.9 and ER G99 12.6 and 13.6.
Fast Fault Current Injection	Reactive current injection required each time the voltage falls below the nominal voltage levels in ECC.6.1.4. The reactive current injected should progressive increase as the voltage drop increases with any residual current being supplied as active current. There should be a smooth control between steady state operation and faulted conditions

These criteria are important. The requirements for fault ride through are well documented in numerous texts and the reader is encouraged not only to refer to the material included in the appendices within this report but also Grid Code Consultation GC0100 which is available from the link below.

https://www.nationalgrideso.com/sites/eso/files/documents/Final%20Workgroup%20consultation_0.pdf

In summary when a generator is exposed to a close up solid three phase short circuit fault there is a requirement to inject maximum reactive current so as to maintain System voltage and for longer term voltage dips there is a requirement for a contribution of reactive current with the residual to be supplied as Active Current so as to contribute to Active Power, this being important criteria for the support of system frequency in the event of a voltage dip.

As an initial starting point, the German model was first considered as shown in Figure 4.0 where the injected reactive current is a function of the voltage.

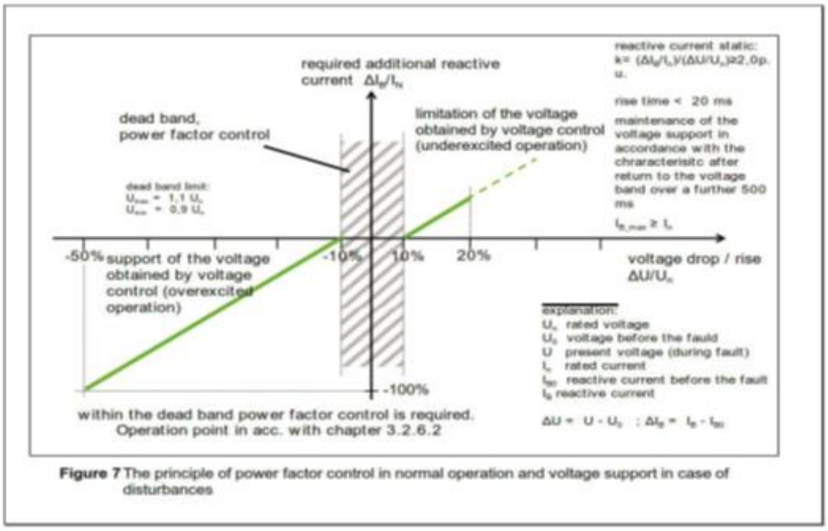

Figure 4.0

This interpretation uses the following formula's

$I_R = \Delta V.k + I_{Prefault}$

I_R – The Reactive Current injected in pu during the fault in pu. This cannot exceed 1.0pu on the MVA Rating

$V = V_{prefault} - V_{deadband} - V_{retained}$

$V_{prefault}$ – Is the Prefault Postive Phase Sequence voltage in pu

$V_{deadband}$ - Is the deadband either side of nominal voltage set at 0.1pu

$V_{retained}$ – Is the positive sequence voltage at the Grid Entry Point or User System Entry Point under faulted conditions

K – Is the voltage gain factor set to 1

$I_{prefault}$ – Is the prefault reactive current in pu.

These concepts were further explored and presented to the workgroup in September 2018, which resulted in the following revised voltage / reactive current diagram shown in Figure 5.0.

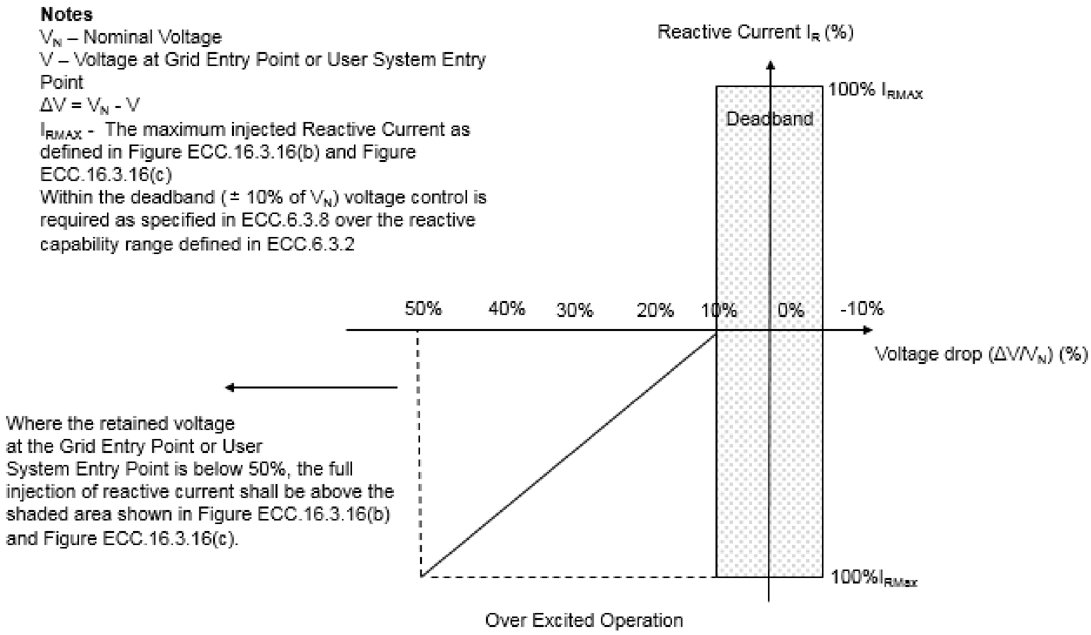

Figure 5.0

In addition, corresponding legal text was also developed. At this stage, a number of Workgroup members expressed concern over the behaviour of Power Park Modules and HVDC Systems during unbalanced faults and that the performance of plant can vary quite significantly between full converter based plant or DFIG derived equipment. A number of concerns were also expressed with regard to operation between steady state and under faulted conditions.

At this stage two options were suggested by the workgroup. One was to consider the approach adopted as discussed in September, another was to adopt an approach similar to that proposed in EN 50549. EN50549 is much more specific in its treatment of unbalanced injection and the use of positive and negative components. These issues start to become complex very quickly and whilst two versions of the legal text were drawn up (ie one drawn up based on the discussion held in September and one drawn up based on EN 50549) the general view was that the initial approach suggested in September should be the one taken forward as the EN50549 is complex with the conclusion that any form of individual phase behaviour would be outside the scope of the workgroup.

However some very useful findings came out of these discussions in which it was agreed that in adopting the September option, the deadband should be changed to insensitivity and a number of detailed examples should also be prepared outlining how a plant would be expected to respond when operating in full lead or full lag and then subsequently exposed to range of voltage dips of various degrees ranging from 85% retained voltage to 10% retained voltage.

In addition, to reflect the difference between different technologies (ie full converter or DFIG etc), a relaxation was introduced into the drafting which effectively permitted a temporary drop below the shaded area provided this was agreed with National Grid. There is some concern how this could be interpreted as such solution would be to ensure the volume of reactive current supplied exceeds the minimum requirement specified in Figures ECC.6.3.16(b) and ECC.6.3.16(c).

In light of these discussions, a further presentation (with examples) and revised legal text was presented to the workgroup in December 2018. A copy of this presentation is shown in Annex 2D which includes the examples.

The revised voltage / reactive current characteristic is shown in Figure 6.0 below.

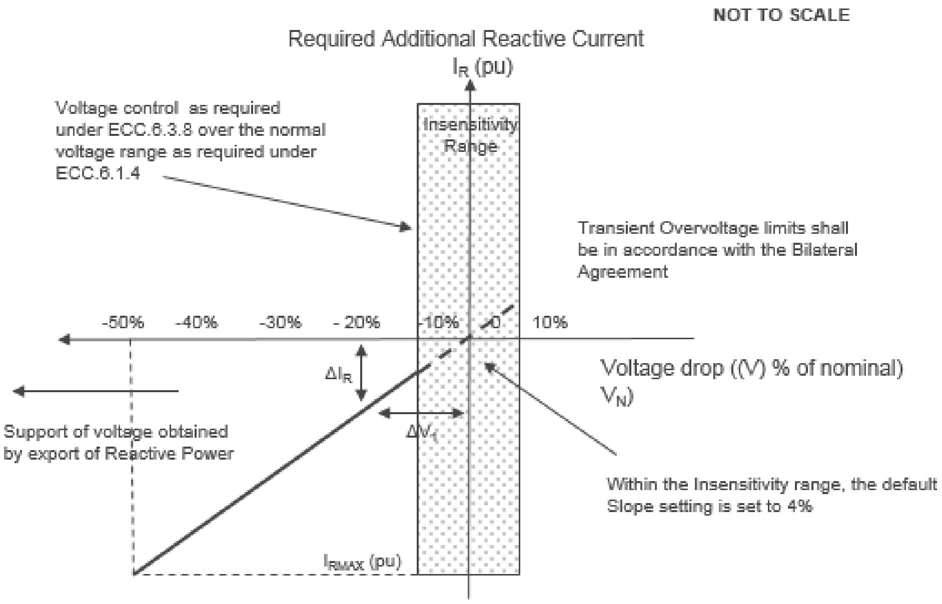

Figure 6.0

Where the corresponding formula's are:-

Where:-

V_N – Rated Voltage

V - Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R - Additional reactive current where:_

$I_R = \Delta V_1.k + I_{Prefault}$ (when V is between 50% and less than 90%)

$I_R = I_{RMAX}$ (when V is less than 50%

as defined by Figure ECC.16.3.16(b) or Figure ECC.16.3.16(c))

(I_R - Is the additional Reactive Current injected during the fault in per unit. This cannot exceed 1.0pu on the MVA Rating of the Power Park Module or HVDC Equipment as detailed in ECC.6.3.16.1.5)

In this approach where the voltage exceeds 50% the formula $I_R = \Delta V_1.k + I_{Prefault}$ and below 50% retained voltage, full reactive current would be required to be supplied.

At this point a number of stakeholders expressed concern over the mode change at retained voltages of 50% and at this meeting it was suggested that a formula based approach should be used over the entire voltage operating range. As a result, the following approach formula was proposed which would apply over the full voltage range.

V Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R The reactive current supplied under fault conditions where:-

$$I_R = \Delta V_1.k + I_{Prefault} \quad (1)$$

I_R The Reactive Current supplied under fault conditions shall be above the shape shown in Figure ECC.16.3.16(b) and Figure ECC.16.3.16(c) with the peak steady state reactive current defined by Equation (1) above. This value is capped at a maximum of 1.0pu.

There is no requirement for I_R to exceed 1.0pu (I_{RMAX}) but this would not preclude a Power Park Module (or any constituent Power Park Unit) or HVDC Equipment from supplying more should it wish to do so.

ΔV_1 $= V_{prefault} – V_{insensitivity} – V_{retained}$

$V_{prefault}$ Is the Prefault Positive Phase Sequence RMS voltage in per unit

$V_{insensitivity}$ Is the voltage either side of nominal voltage and set at any value between 0 and 0.1 as agreed between The Company and the Generator - Default setting 0.1 unless otherwise agreed.

$V_{retained}$ Is the retained positive sequence voltage at the Grid Entry Point or User System Entry Point (under fault conditions)

k Is the gain factor (range proposed 2 – 7) – Default setting 2.5

$I_{prefault}$ is the prefault reactive current in per unit

The prefault reactive current ($I_{prefault}$) for a future fault ride through event, shall be determined when the voltage has returned above the minimum levels specified in ECC.6.1.4,

I_{RMAX} The maximum current which shall, as a minimum, be above the shaded areas defined by Figures ECC.16.3.16(b) or ECC.16.3.16(c). There is no requirement for the maximum supplied current to exceed 1.0pu.

Numerous examples of this approach at the extreme operating range (ie low and high pre-fault voltages) were prepared and these are shown in Appendix X and forwarded to the workgroup in January 2019.

For completeness two examples are shown below. In both cases the retained voltage is set at 50% with one case operating at a low pre-fault voltage and in another a high pre-fault voltage.

First Example –

Power Park Module operating at full MW output and full MVAr output – volt drop to 50% and $V_{insensitivity}$ set to 0.1 and K = 2.5

- Wind farm is operating at 100MW output and 0.95 PF lagging (ie 32.8MVAr or export to the System)
- $I_R = \Delta V_1.k + I_{Prefault}$
- And $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained}$
- If V Prefault = 0.96p.u and Q max = 0.95 PF lag on a 4% droop
- $V_{insensitivity} = 0.1$ p.u
- In this case the retained voltage ($V_{retained}$) is 0.5 pu
- $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained} = 0.96 - 0.1 - 0.5 = 0.36$
- $I_{prefault} = \sin(\arccos 0.95) = 0.312$pu
- $I_R = \Delta V_1.k + I_{Prefault} = 0.36 \times 2.5 + 0.312 = 1.212$ pu – *capped at 1.0pu reactive current*
- *IR at 60ms = (0.65 x* ΔV_1*.k)* + $I_{prefault}$ = 0.65 x 2.5 x 0.36 + 0.312 = 0.897 pu

Which when superimposed on Figure ECC.6.3.16(b) and ECC.6.3.16(c) results in Figure 7.0 and Figure 8.0

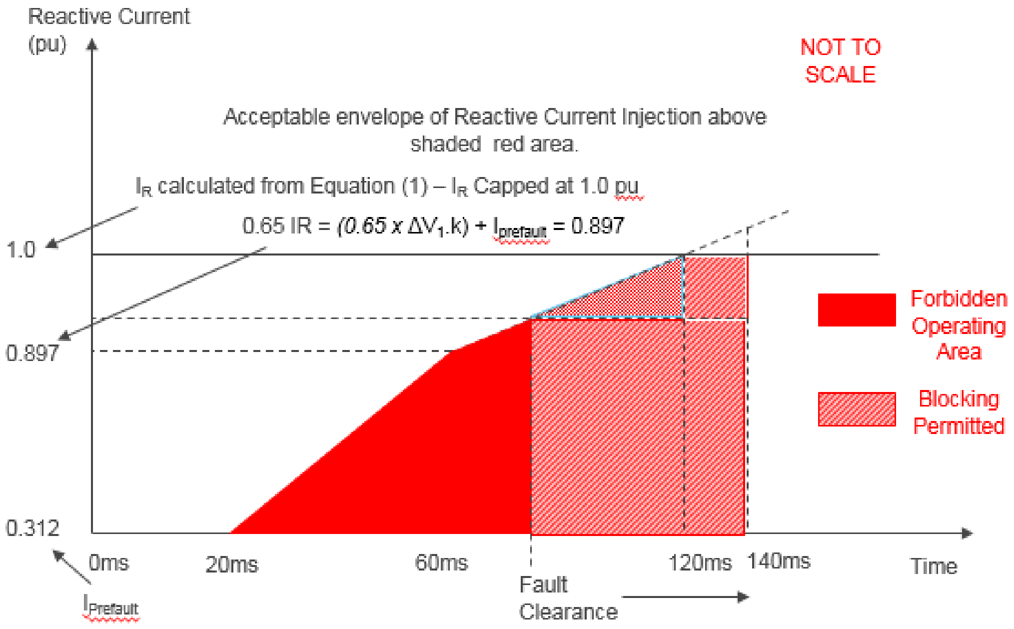

Figure 7.0

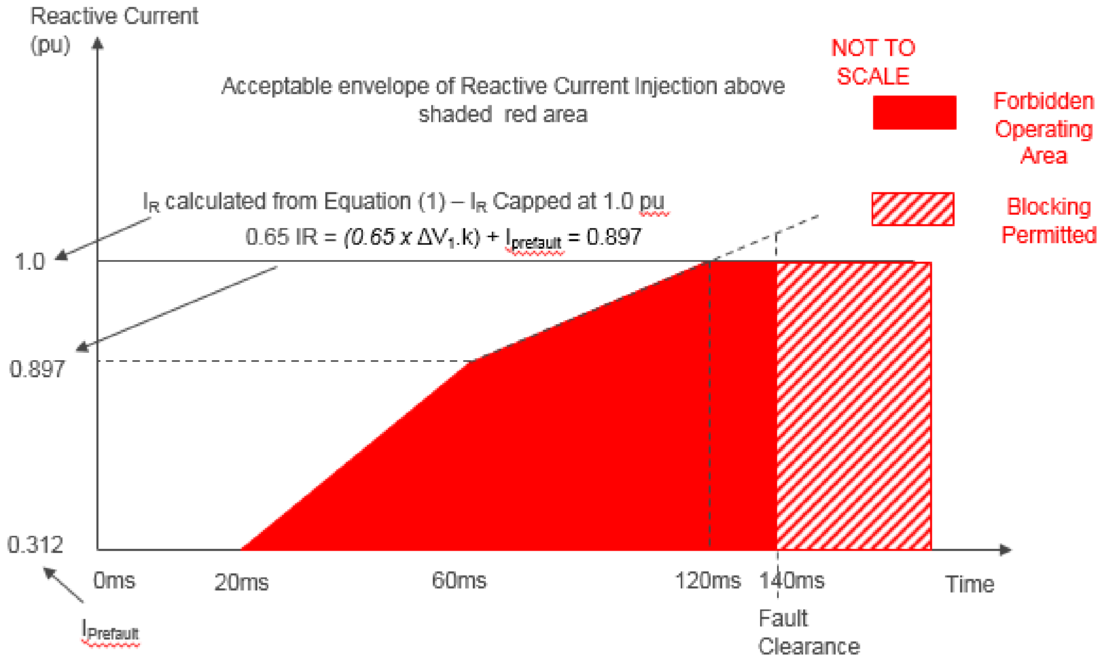

Figure 8.0

Second Example

Power Park Module operating at full MW output and full MVAr output – volt drop to 50% and $V_{insensitivity}$ set to 0.1 and K = 2.5

- Wind farm is operating at 100MW output and 0.95 PF leading (ie 32.8MVAr or import to the System)
- $I_R = \Delta V_1.k + I_{Prefault}$
- And $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained}$
- If V Prefault = 1.04p.u and Q max = 0.95 PF lead on a 4% droop
- $V_{insensitivity} = 0.1$ p.u
- In this case the retained voltage ($V_{retained}$) is 0.5 pu
- $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained} = 1.04 - 0.1 - 0.5 = 0.44$
- $I_{prefault} = \sin(\arccos 0.95) = -0.312$pu
- $I_R = \Delta V_1.k + I_{Prefault} = 0.44 \times 2.5 - 0.312 = 0.788$pu
- *IR at 60ms = (0.65 x ΔV_1.k)* + $I_{prefault}$ = (0.65 x 2.5 x 0.44) - 0.312 = 0.403 pu

Which when superimposed on Figure ECC.6.3.16(b) and ECC.6.3.16(c) results in Figure 9.0 and Figure 10.0

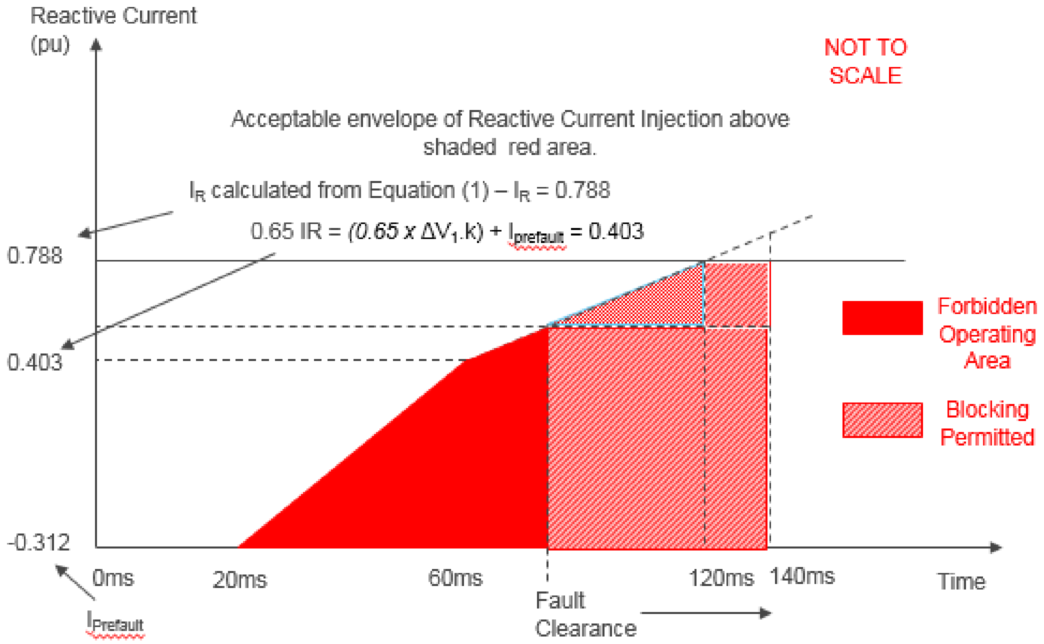

Figure 9.0

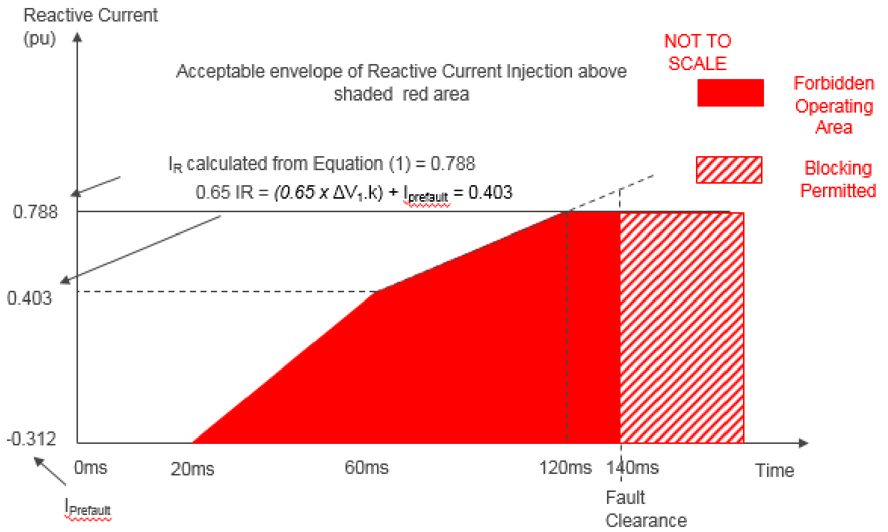

Figure 10.0

As can be seen in the leading example the injection of reactive current is lower than that in the lagging case which means that the gain factor (k) would need to be increased if full reactive current was to be achieved for a voltage drop of 50%. Whilst it is accepted that the delta (ie the reactive current swing) between the two is broadly similar, full reactive injection would be required under a faulted condition.

To address this concern, the effect can be limited by changing the formula so that the additional reactive current becomes $I_R = \Delta V_1.k + |I_{Prefault}|$ where $I_{prefault}$ becomes the modulus of $I_{prefault}$ and ΔV_1 simply becomes $V_{prefault} - V_{retained}$. Whilst there will be a slight difference between the reactive current injected between unity power factor and full lead or full lag, full reactive current would be obtained for a retained voltage of 0.5pu. This also means the K factor can be retained at 2.5 although in simplifying the formula this would require the need to make sure developers and manufacturers are comfortable with the transition from the steady state mode between the normal operational voltage of 0.9pu to 1.05pu and a faulted condition. The revised voltage drop / reactive current characteristic is shown in Figure 11.0.

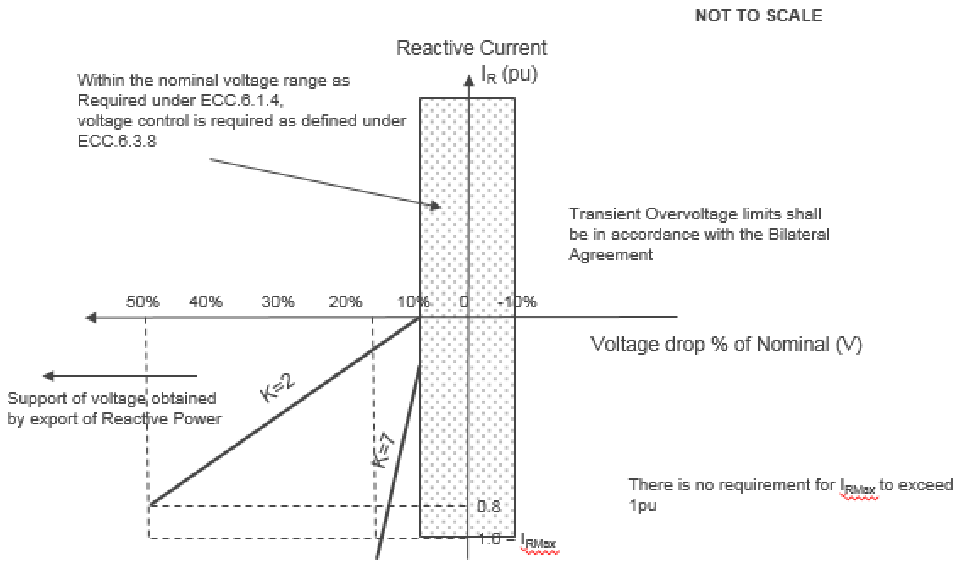

Figure 11.0

Where:-

V - Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R - The reactive current supplied under fault conditions where:-

$I_R = \Delta V_1.k + |I_{Prefault}|$ Equation (1)

I_R The Reactive Current supplied under fault conditions shall be above the shape shown in Figure ECC.16.3.16(b) and Figure ECC.16.3.16(c) with the peak steady state reactive current defined by Equation (1) above. This value is capped at a maximum of 1.0pu.

There is no requirement for I_R to exceed 1.0pu (I_{RMAX}) but this would not preclude a Power Park Module (or any constituent Power Park Unit) or HVDC Equipment from supplying more should it wish to do so.

$|I_{prefault}|$ is the modulus of the prefault reactive current in per unit the prefault reactive current ($I_{prefault}$) for a future fault ride through event, shall be determined when the voltage has returned above the minimum levels specified in ECC.6.1.4,

ΔV_1 = $0.9 - V_{retained}$

Vprefault Is the Prefault Positive Phase Sequence RMS voltage in per unit

$V_{retained}$ Is the retained positive sequence voltage at the Grid Entry Point or User System Entry Point (under fault conditions)

k Is the gain factor (range proposed 2 – 7) – Default setting 2.5

IRMAX There is no requirement for the maximum supplied reactive current to exceed 1.0pu.

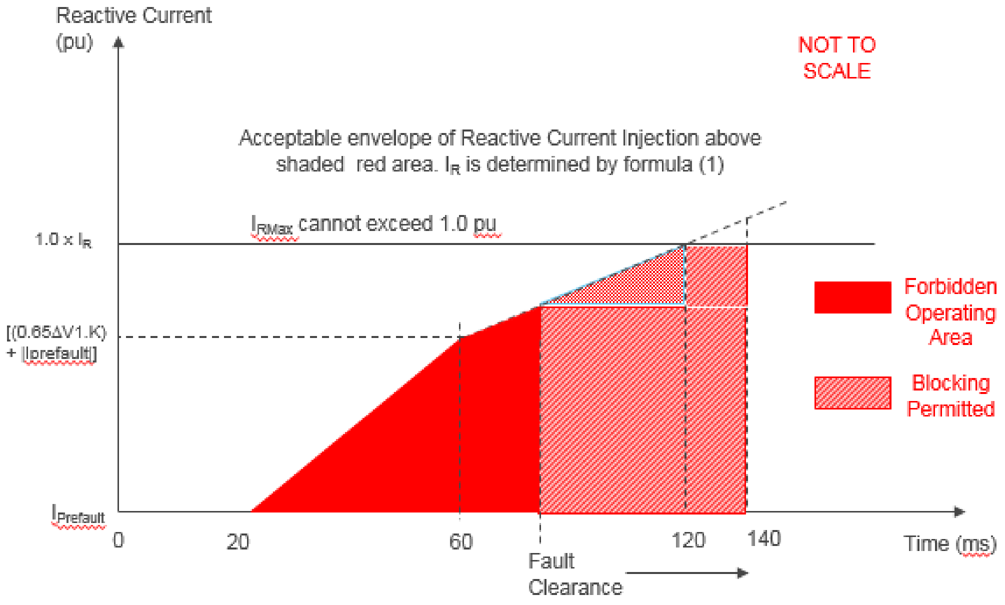

Figure 12.0

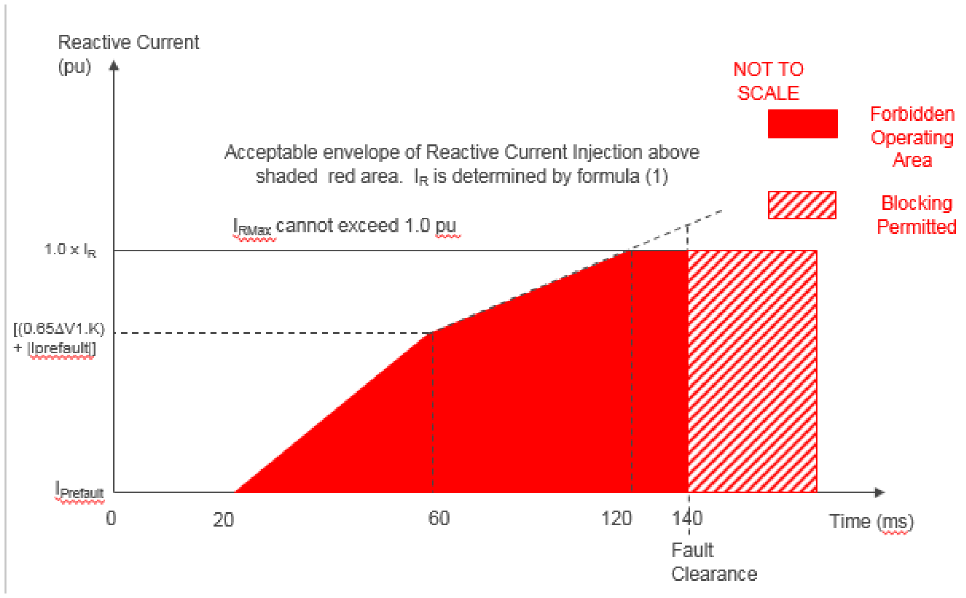

Figure 13.0

The problem with the above approach however is that there is still a difference between the reactive current injected and the pre-fault operating condition. There is also the risk of hunting between the normal voltage operating range and a fault ride through condition. Figure 14.0 below shows a more detailed representation of the requirement between steady state operation and a fault ride through condition.

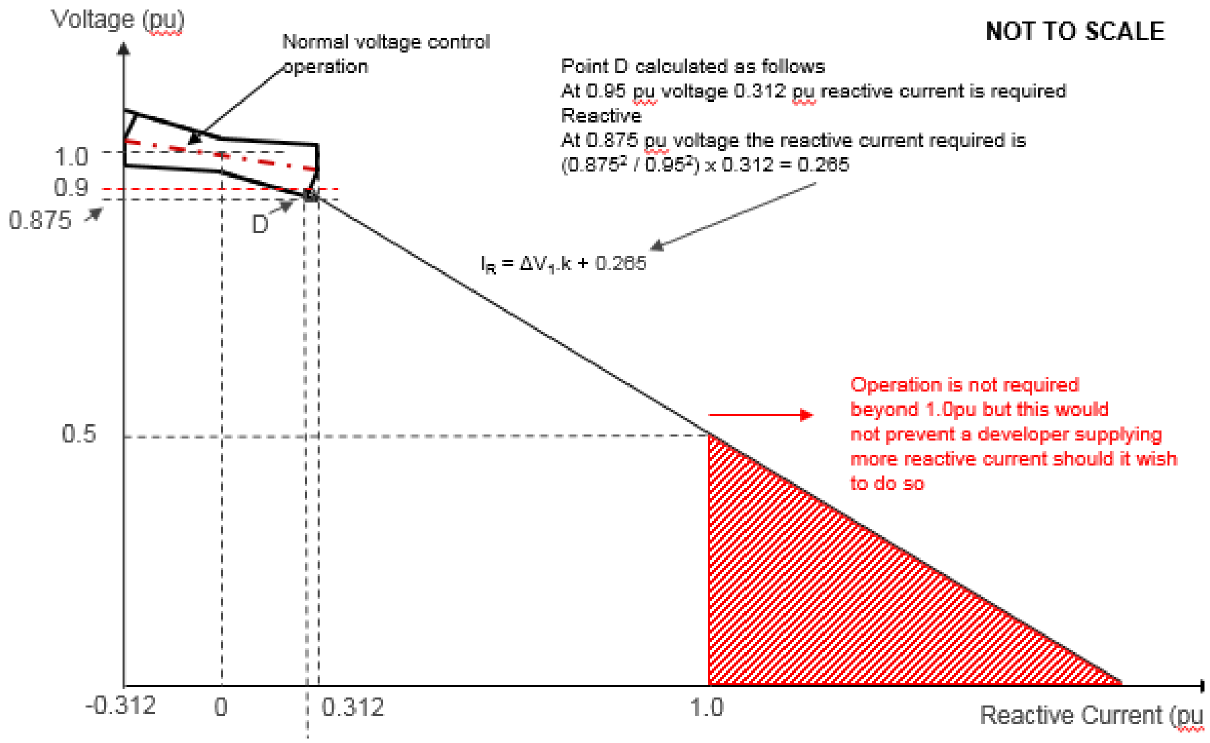

Figure 14.0

As part of this approach the proposal was for the reactive current injection to be defined by the following formula.

$$I_R = \Delta V_1.k + 0.265$$

and

$$\Delta V_1 = 0.9 - V_{retained}$$

In this case the gain factor K was set at 2.5 but can be varied between 2 and 7.

The advantage of this approach is that the reactive current injection will be the same irrespective of whether the pre fault operating point. In addition, as soon as the voltage drops to 0.5pu with a gain factor of 2.5, a reactive current injection of 1.0pu will be delivered.

The problem with this approach is that some developers and manufacturers would struggle with the requirement especially in the common case for distribution connected modules if the plant was operating in power factor control mode or reactive power control mode and the Connection Point Voltage remained at 0.9pu and the generator was operating under full import – although such an operating point itself is not likely. To address this issue, it was suggested at the February 2019 Workgroup meeting that the normal voltage operating envelope should be retained and an envelope of operation defined between the two black lines (ie between the extreme ends of the voltage operating range (between 0.9pu and 1.1pu voltage) and the intersection of 0.5 pu and 1pu reactive current). This characteristic is shown in Figure 15.0 below but would at least ensure a progressive injection of reactive current between 0.9pu and 0.5 pu voltage whilst ensuring below 0.5pu voltage the full 1.0pu reactive current would be delivered.

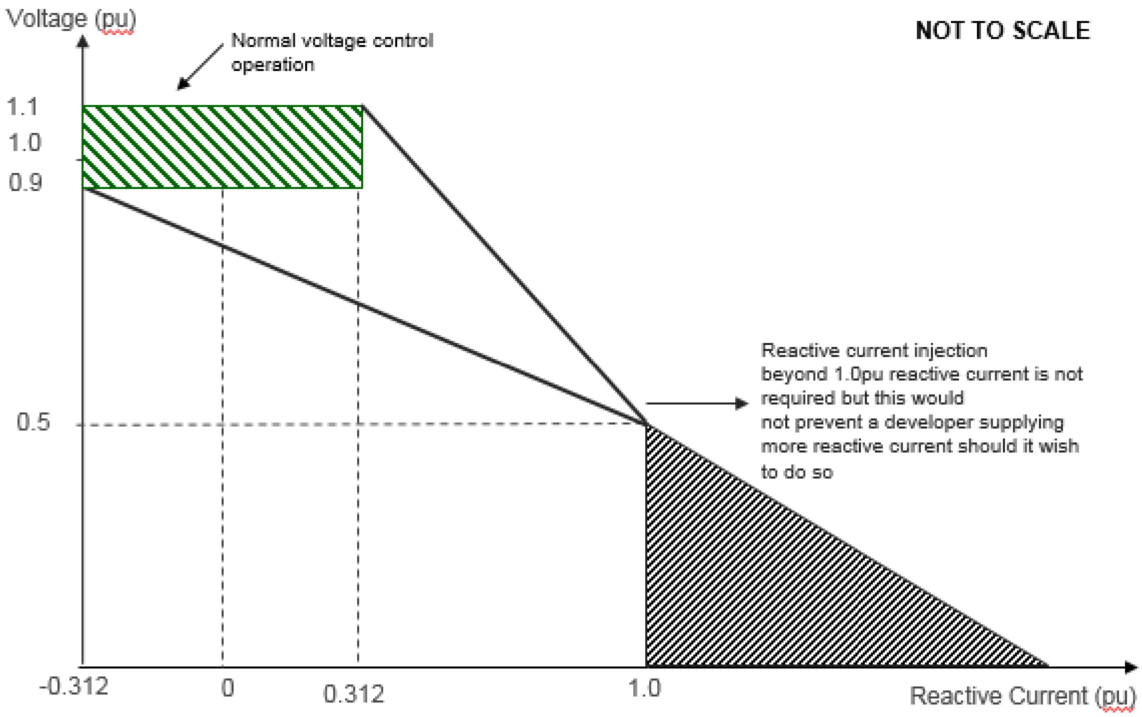

Figure 15.0

In this case, the point was raised that a plant could be operating at 0.9pu in a leading mode of operation at 0.9 pu voltage which could only apply in a power factor or reactive power mode of operation and even then in the unlikely event this were to occur, the voltage would have to drop for a small amount even to get zero injection of reactive current although there would be a delta change (i.e. the difference between the final reactive current injection and the pre-fault reactive current injection) in transiting from a fully leading power factor to unity.

To address this concern, two points were raised. The first, that irrespective of the operating point within the normal voltage operating range, the locus of I_R should converge to the 0.5pu voltage / 1.0pu reactive current coordinate so as not solely to give a minimum performance requirement. Secondly, some concern was expressed as to how this requirement would interface with Figures ECC.6.3.16(b) and ECC.6.3.16(c). A comment was also noted that the upper boundary would not be required.

To illustrate the concept of this approach, two examples are shown below. It should be noted that the diagrams associated with these examples are for illustration purposes only and not to scale.

Figure 16 shows an illustrative requirement of the behaviour expected from a plant operating in the leading mode of operation and the I_R value required when subject to a voltage dip of 0.7pu at the connection point.

In this case, the pre-fault operating condition is assumed to be arbitrarily operating at 1.07pu voltage and the reactive current is -0.3pu. This is shown by the blue circle in the green shaded area. The reactive current injection can take any shape being linear or non-linear but would need to be on or above the blue dashed line shown in Figure 16 constructed between points A and B.

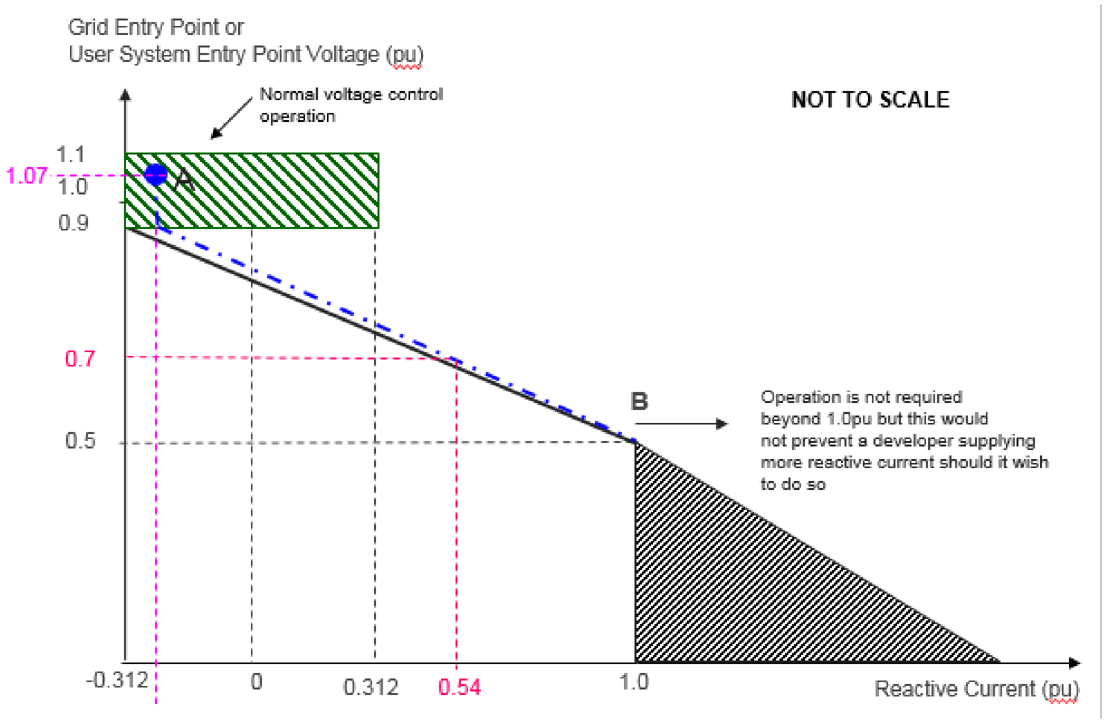

Figure 16.0

For the purposes of this example we are assuming the Power Park Module is exposed to a voltage dip of 0.7 pu. At 0.7pu voltage this corresponds to I_R of 0.54 pu reactive current as shown by the purple dashed line and where it intersects with the blue dashed line. I_R would need to be greater than or equal to 0.54.

In terms of time frames and reactive current injection and the minimum performance requirement that would be expected is shown in Figures 17 and 18. In summary the reactive current injection would need to be 0.54pu or above by 120ms after fault inception, with any residual current (ie taking into account the converter rating) being supplied as active current. There is no real difference between these two figures other than in respect of the fault clearance time.

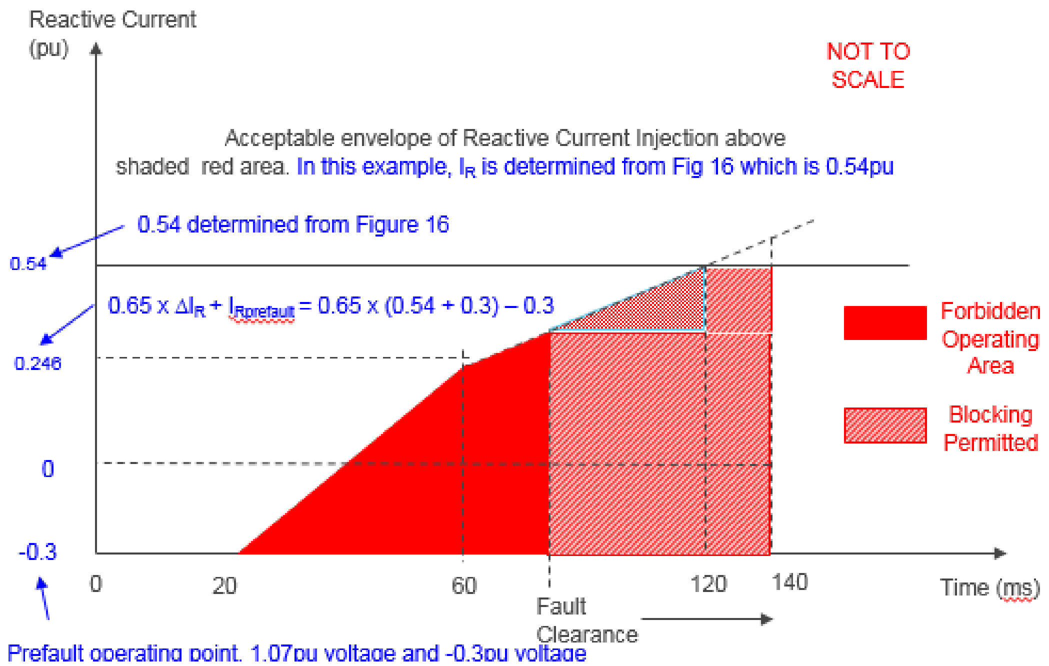

Figure 17

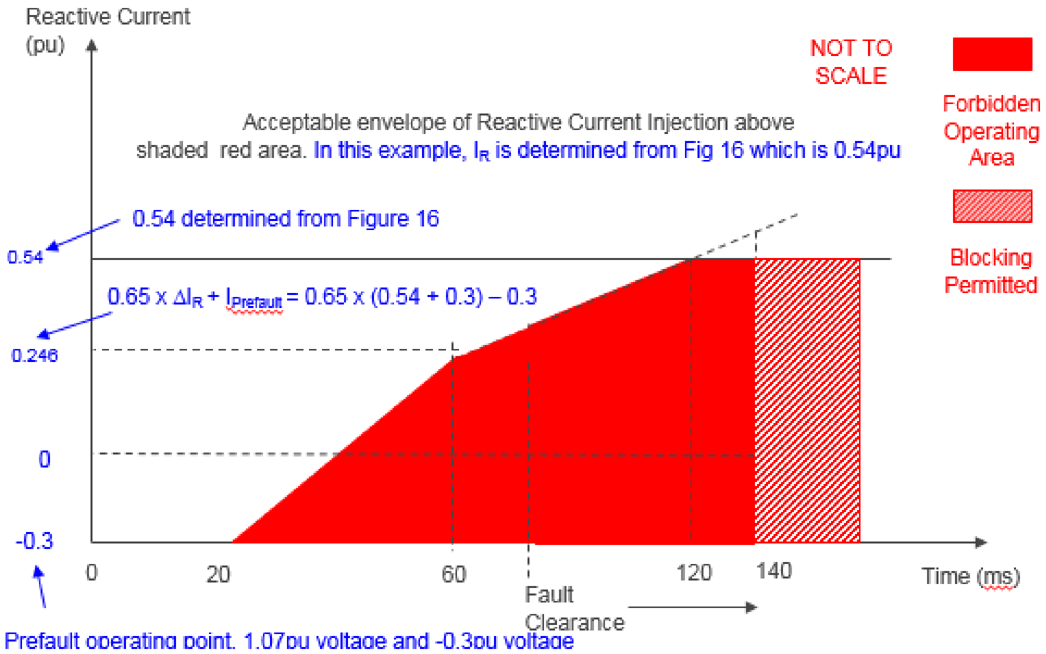

Figure 18

Example 2 is shown in Figure 19 which shows an illustrative requirement of the behaviour expected from a plant operating in the lagging mode of operation and the resultant I_R required when subject to a voltage dip of 0.7pu at the connection point.

In this case, the pre-fault operating condition is assumed to be arbitrarily operating at 0.96pu voltage and the reactive current is 0.312pu. This is shown by the brown circle in the green shaded area. Applying the same approach as in example 1, the brown dotted line constructed between points A and B of Figure 19 indicates the I_R required as a function of the retained voltage. However we need to ensure that the rating of the plant is not exceeded and therefore an additional pink line at point C is drawn. This reduction is permitted as the Grid Code requires full reactive capability to be provided over a voltage range of 1.05pu to 0.95pu. Below 0.95pu voltage, a drop in the reactive power export is permitted as it is possible a number of developers may choose to use fixed capacitors to contribute to voltage control in which case the reactive power falls off with the square of the voltage. This characteristic showing the allowed fall in reactive power is shown in Figures ECC.A.7.2.2b and ECC.A.7.2.2c of Appendix 7 of the Grid Code European Connection Conditions.

For the purposes of this example, we are assuming the Power Park Module is exposed to a voltage dip of 0.7 pu. At 0.7 pu voltage this corresponds to a I_R of 0.64 pu reactive current as shown by the purple dashed line and where it intersects with the pink dashed line at 0.7pu voltage.

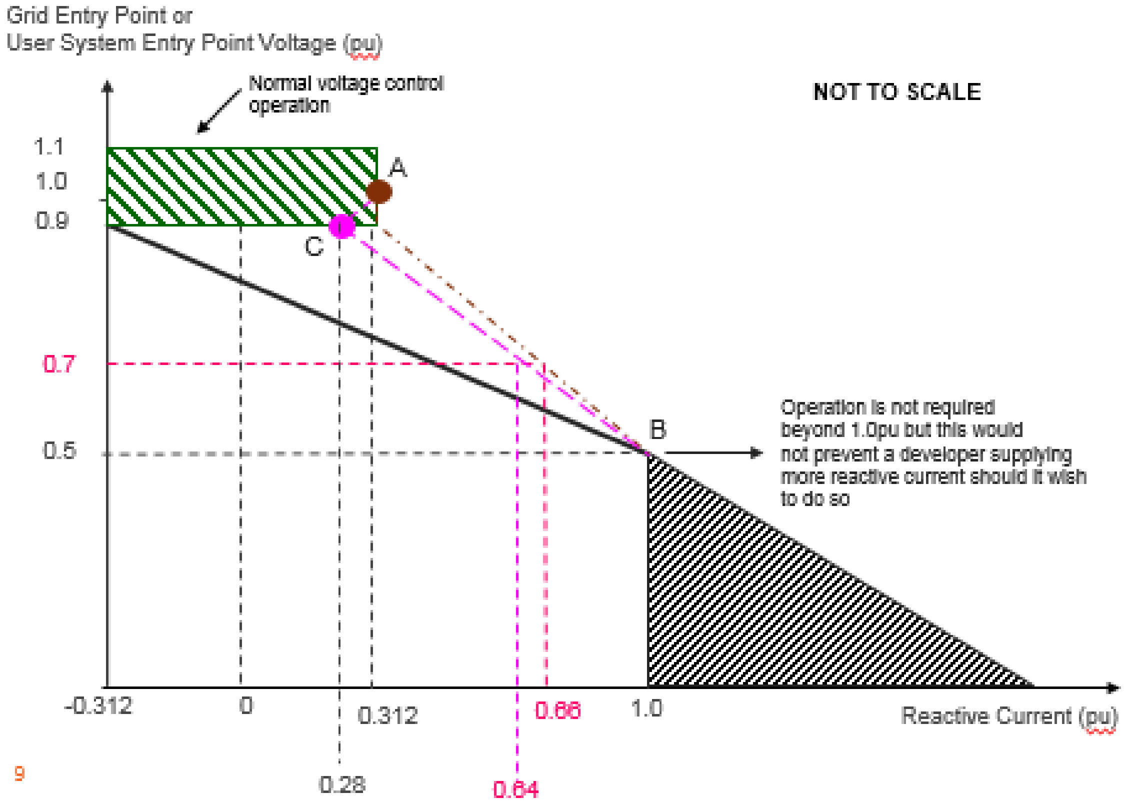

Figure 19.0

In terms of time frames and reactive current injection the minimum performance requirement that would be expected is shown in Figures 20 and 21. There is no real difference between these two figures other than in respect of the fault clearance time. In this example the green hashed area is showing the effect of the pre-fault operating condition of the Power Park Module.

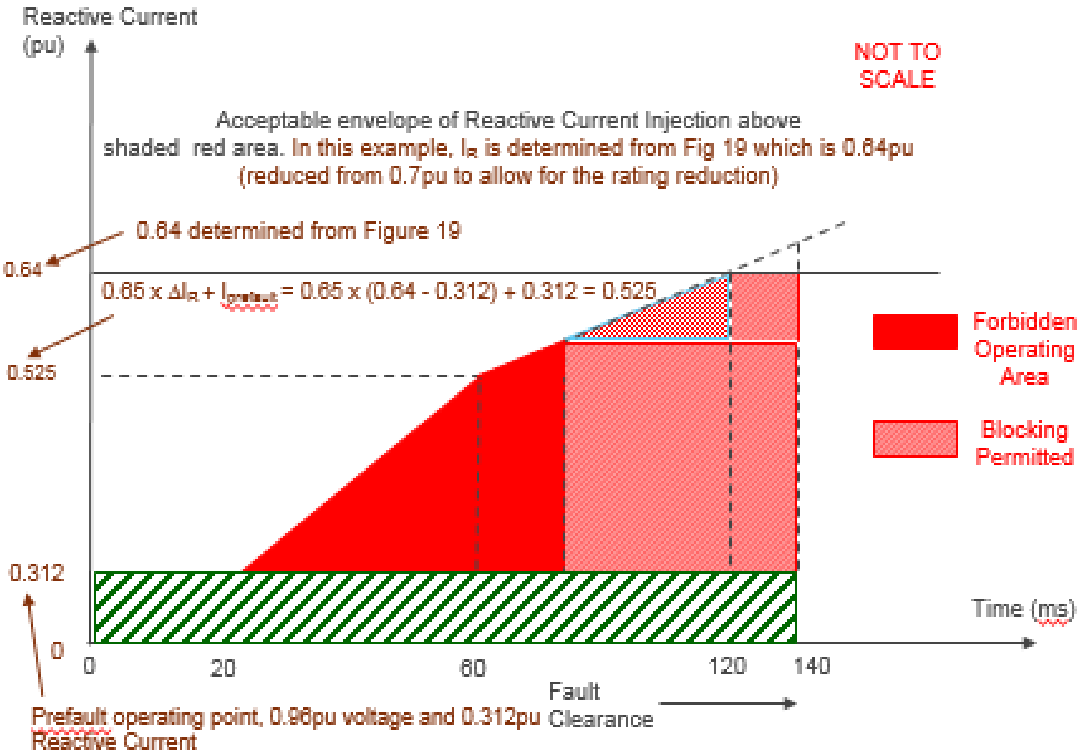

Figure 20.0

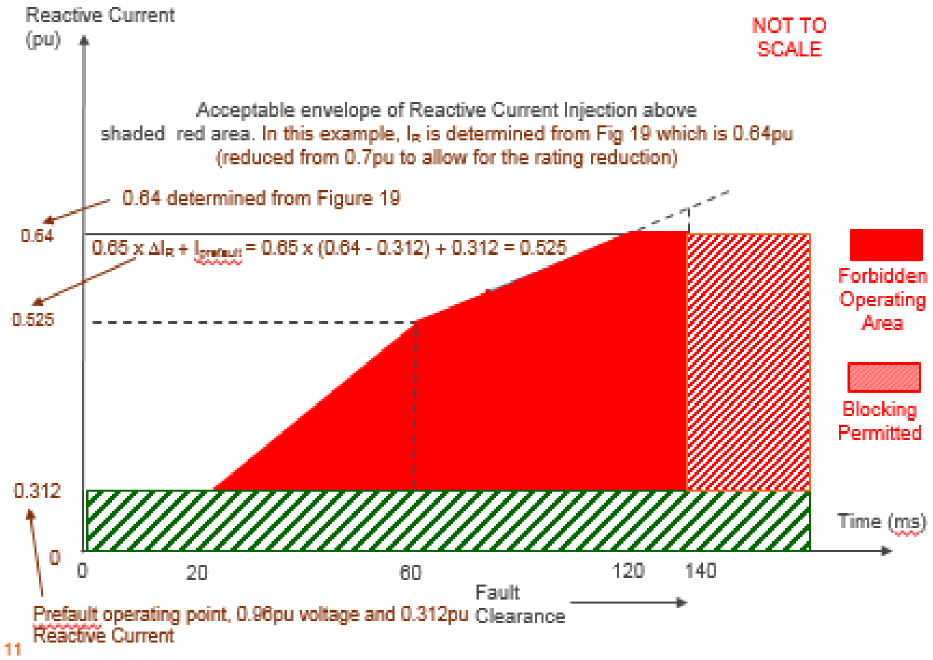

Figure 21

The above approach was discussed amongst the workgroup at the meeting on 7 February 2019 and re-discussed at a later meeting on 13 February 2019.

The key documents affected by this modification proposal are the Grid Code and EREC G99. There are no other effects on other industry documents.

As part of the proposal following workgroup discussion it was agreed to separate out the requirements for balanced and unbalanced faults and RfG leaves the behaviour of unbalanced faults and fast fault current injection performance to the TSO.

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

No

Consumer impacts

There are no consumer impacts

4 Workgroup Discussions

The Workgroup convened four times between July 2018 and February 2019 to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable Grid Code Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Workgroup discussed a number of the key attributes under GC0111 and these discussions are described below.

Workgroup 1 – 4 July 2018

The slides presented by National Grid as Electricity System Operator are attached in Annex 2A. In summary, this concentrated on the background to the issue, the defect and the key clarification that during a fault there is no requirement for the Power Park Module to exceed its rating. In addition, the point was also raised with regard to the defect in ECC.6.3.16.1.4 which states "the reactive current injected from each Power Park Module or HVDC Equipment shall be injected in proportion and remain in phase to the change in System voltage at the Connection Point or User System Entry Point during the period of the fault.

At the workgroup meeting it was advised that some form of specification would be required to detail how the reactive current should vary with depressed voltage and address the linkage between the fault ride through requirements in ECC.6.3.15 and the fast fault current requirements in ECC.6.3.16.

Workgroup 2 – 10 September 2018

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2B. The NGESO representative advised that the aim of the legal text would be to keep the requirements as generic but robust as possible. The following is the discussion on the proposed draft legal text as of 10 September 2018.

A Workgroup member stated that he found it difficult to follow all of the proposed graphs and therefore suggesting to only keep the graphs for Transmission connections but it may be useful to specify a description which would be equally effective.

A Workgroup member stated that in Figure ECC.16.3.16(a), a statement on what the maximum voltage and proportionality criteria needed to be clarified. It was agreed that this is what the graph was trying to achieve.

A Workgroup member queried whether the figures in ECC.16.3.16(a) are absolute figures. The NGESO representative tried to address this issue but further thought and clarity was needed for the legal text.

The NGESO representative referred to Figure ECC.3.16(b) and stated that the Workgroup needs to consider whether this would be a rise time or a settlement time. He explained that the reactive current has to be above the red section on the figure. The control performance should be adequately damped.

Another Workgroup member stated that their comments had already been addressed and they will forward some comments by E Mail to aid the drafting of the legal text.

A Workgroup member queried how the changes on RfG were going to be taken forward. The NGESO representative confirmed that the RfG requirements were captured in GC0100 and these have now been implemented into the Grid Code. However, it did not capture faults greater than 140 ms which have been retained as part of the existing GB Code drafting.

A Workgroup member stated that it is common for type tests to be completed for fault ride through. There may not be clear testing requirements so this will need some clarity.

The NGESO representative informed the Workgroup that it was discussed that it is not possible to demonstrate on a module basis but you can do so on individual turbines basis.

There is a challenge in articulating this in the Grid Code legal text as the Grid Code is based around a performance requirement for the module rather than the turbine. Although the text is written with respect to Power Park Module performance, the proposed text does provide a clause for assessment at a unit level.

A Workgroup member queried what would happen if the voltage drops below 1 per unit ie what would be the consequences as the Power Park Module could include various combinations as there is a phase between operation within the normal voltage operating range (ie ±10%) and under fault ride through conditions. The NGESO representative stated that they would review this when looking at the legal text.

The NGESO representative clarified that in relation to slide 11 that below 50% is a priority for reactive current injection and above 50% there should be a minimum requirement to supply reactive current with any residual being supplied as active current. It was agreed that it needs to clarified which of these are the priority and this needs to be clearly articulated. A Workgroup member queried whether there needed to be an example around where the voltage drops below 50%. The NGESO representative stated that where the voltage drops below 50% the reactive current should be prioritised.

A Workgroup member queried whether the proposal was asking for absolute levels of current. The NGESO representative stated that he would review whether these are absolute values or delta values.

A Workgroup member raised in relation to ECC.6.3.16.1.4 that if this is a requirement, then this should be in the compliance section of the Grid Code as opposed to the European Connection Code. The NGESO representative agreed to discuss this with the National Grid Compliance Team before updating the legal text.

A Workgroup member queried where the items specified in Article 20 are reflected in the draft legal text? The NGESO representative stated that as part of the mapping exercise that was completed as part of the GC0100 consultation.

The NGESO representative confirmed that he would take the Workgroup feedback on board, amend the legal text and recirculate it around the Workgroup for comment. Part of this analysis would be to ensure there is consistency between the proposed legal text and the European Connection Codes.

<u>Workgroup 3 – 7 November 2018</u>

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2C.

Following discussions and emails in between the Workgroups, the NGESO representative drafted and presented to the Workgroup two versions of the legal text – 1A and 1B. As noted above version 1A was based on the draft text discussed at the September meeting and version 1B incorporates elements from the fast fault current injection requirements of EN50549.

A Workgroup member stated that they would suggest not using pre-fault in the formula on slide 7 of the slide pack. In addition, some practical examples would be helpful to understand the requirements better.

A Workgroup member observed that the changes to voltage would have a minimal impact on Distribution Network Operators.

In relation to the legal text – version 1A, the NGESO representative stated that the diagram on slide 10 is in relation to the sum of all the turbines.

In relation to legal text – version 1B, the NGESO representative stated that incorporating EN50549 means that it becomes very complex very quickly but does more easily address the issue of unbalanced faults. Based on discussions prior to the Workgroup, the NGESO representative stated that it seemed that the majority of the Workgroup were in favour of legal text -version 1A although it was recognised that it needed further work including agreeing a recommendation for implementation. Legal text 1A will result in minimal impact on the industry when devising the solution.

A Workgroup member queried whether the EN50549 requirements link to HVDC equipment and queried whether any Workgroup members manufacture that kind of equipment to ensure their view is reflected. The NGESO representative confirmed that this did relate to HDVC Equipment and that there are Workgroup members from Siemens who manufacture HVDC equipment.

The Workgroup unanimously agreed that the Workgroup should proceed with version 1A of the legal text for the solution.

The Workgroup reviewed the legal text by exception to allow the legal text to be further developed.

A Workgroup discussed the timeline, and agreed that they wanted to talk through some worked examples before deciding whether to proceed to a Workgroup consultation.

The Workgroup discussed the terms of reference set by the Grid Code Review Panel:

a. Implementation and costs

   In terms of costs, the NGESO representative stated that the implementation will be linked to contracts and that the aim is to minimise any costs as the changes to the legal text are for clarification purposes only and should not result in additional cost.

b. Develop draft the legal text

   This is currently in progress and will be completed to be submitted with the Workgroup Report to the Grid Code Review Panel.

c. Consider whether any further industry experts or stakeholders should be invited to participate in the Workgroup

   This has been done on an ongoing basis. The Workgroup is comprised of industry experts. The NGESO representative expressed his gratitude for the participation and help given so far in developing the solution.

d. Consider the materiality of the change

   The materiality of the change is low as the purpose of the modification is to provide clarity to industry.

e. Requirement for a Workgroup Consultation

   This is unknown until the Workgroup has seen some worked examples. At that point the Workgroup can decide whether to proceed to a Workgroup consultation.

f. Review the trigger voltage and Fault Ride Through requirements and whether the changes are compatible

   The NGESO representative stated that this is a National Grid issue and he believes this is minimal. He will continue to consider this as the solution is developed.

One Workgroup member provided a spreadsheet showing plant performance, which was circulated to the Workgroup.

Workgroup 4 – 6 December 2018

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2D.

The NGESO representative presented to the Workgroup a presentation which included a number of worked examples to demonstrate how the proposed solution would work in practice.

The Workgroup discussed compliance and agreed there needed to be section on compliance legal text included in the solution to complete the modification.

A Workgroup member queried whether there was a need for a further compliance modification as there are a number of issues that needed to be addressed.

The Workgroup agreed to continue to use the term “insensitivity” as opposed to dead band to provide greater clarity to Grid Code users.

A Workgroup member queried when the 20 milliseconds in example 5 starts. It was agreed that NGESO would look at this.

The Workgroup discussed the formula in example 2 of the slide pack (see Appendix 1D) and it was agreed that the NGESO representative would review the formula and re-circulate this around the Workgroup.

On slide 36, The NGESO representative stated that based on the approach set out in slide 36, it is possible to calculate the FFCI Power Park Module performance requirement at the connection point and work back to each turbine.

In terms of the implementation, it was agreed by the Workgroup that the approach should be that it runs from the signing of the contract rather than the completion date of plant installation though care needed to be exercised as the current Grid Code drafting is not that clear.

A Workgroup member asked for the implementation to be clearly set out including how long it will take manufacturers to implement this modification.

Based on the worked examples, the Workgroup agreed that a Workgroup consultation was not necessary or required to develop the solution.

Workgroup 5 – 7 February 2019

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2E.

At this meeting, the NGESO representative outlined the revised thinking based on the stakeholder comments received in January. At this meeting, the NGESO representative highlighted that the current drafting as prepared in December 2018 and circulated to the Workgroup in January 2019 still presented a few issues, but these mainly related to the variation in injected reactive current depending upon whether the plant was operating in a pre fault leading or lagging mode of operation. To this extent the NGESO representative suggested changing the formula as follows:-

$$I_R = \Delta V_1.k + 0.265$$

and

$$\Delta V_1 = 0.9 - V_{retained}$$

The details of this approach are summarised in section 3 however a number of Workgroup members stated that this would cause a number of problems.

The Proposer did note at this stage that they were clear what was required which in principle required injection of reactive current in a progressive manner as the retained voltage starts to fall with the full reactive current injection of 1.0pu required at retained voltages of 0.5pu or less.

As a consequence of this, a number of options were discussed which revolved around a solution defining a criterion around a minimum requirement injection requirement between the normal steady state operating range and the need to inject 1.0pu reactive current at connection point voltages of 0.5pu or less.

A number of slides around this discussion were developed at the meeting and these are shown in Annex 2F. This approach and detailed examples are shown in Section 3 which the Proposer is comfortable with and which is believed to provide the best approach for this solution.

As part of the discussion the issue of compliance was also mentioned and it was advised that developers would be able to have the option of demonstrating compliance at the Generating Unit terminals should they so wish. This will be included in the revised legal drafting.

One Workgroup member expressed concern over the requirement for unbalanced faults. It was suggested that they may wish to raise a Workgroup Alternative to address this issue.

As a post meeting note, NGESO considers that a simple way in which this issue could be addressed is based on the fact that RfG for Fast Fault Current Injection does not apply to

Unbalanced Faults and it down to the TSO to define this requirement. Put simply, and with this flexibility, it would enable the text to revert back to the GB Grid Code requirement pre RfG which simply states that in the case of unbalanced faults, the Power Park Module should inject maximum reactive current without exceeding the transient rating of the Power Park Module or HVDC Equipment whilst any such performance requirement would need to be agreed with NGESO against the control philosophy of the design. This issue was addressed and included in the updated legal text which was discussed with Stakeholders at the Webex held on 13 February. For distribution connected plant there is no pre-existing FFCI requirement and the same approach will be adopted for distribution connected Power Park Modules .

Workgroup 6 Webex – 13 February 2019

Following the meeting held on 7 February 2019, it was proposed to hold the workgroup vote based on an updated workgroup report and legal text which was circulated on 8th February and 11th February respectively. Following the re-issue of this text a number of comments were received and these issues were discussed at the meeting with the decision taken to delay the vote until Workgroup members had been given adequate time to re-assess the workgroup report and legal text.

The final proposal as drafted and the approach proposed is summarised in section 3 of this report. It was also agreed to treat unbalanced faults separately from balanced faults and the legal text has been updated to address this.

During the discussion, one workgroup member suggested ECC.6.3.15.9.2.1(b)(ii) be changed to refer to 0.9pu voltage rather than the minimum voltage levels specified in ECC.6.1.4. The Proposer considered this change but felt it would not be entirely correct as the voltage range varies depending on connection voltage. For example, at voltages of 275, 132 or 100kV the voltage range is ±10% whereas for connection voltages below 110kV the voltage range is ±6%. As such the proposer declined to make this change.

5 Workgroup Vote

The Workgroup believe that the Terms of Reference have been fulfilled and GC0111 has been fully considered.

The Workgroup met on [insert date] 2019 and voted on whether the Original would better facilitate the Applicable Grid Code Objectives than the baseline and what option was best overall.

The Workgroup agreed [unanimously/by a majority of x] that the Original was better that the baseline. The voting record is detailed below.

The Workgroup voted against the Grid Code objectives for the Original Proposal. The Workgroup voted and [x] Workgroup members concluded that the Original Proposal is the best option and the baseline received [x] votes.

In conclusion, the Workgroup supported the [x] as the best option.

The voting record is detailed below:

<u>Vote 1</u> – *does the original facilitate the objectives better than the Baseline?*

<u>Vote recording guidelines:</u>

"Y" = Yes

"N" = No

"-" = Neutral

Workgroup Member	Better facilitates AGCO (i)	Better facilitates AGCO (ii)?	Better facilitates AGCO (iii)?	Better facilitates AGCO (vi)?	Better facilitates AGCO (v)?	Overall (Y/N)
Mike Kay (Proposer)						
Original						
Voting Statement: xx						
Tony Johnson						
Original						
Voting Statement: Xx						
Isaac Gutierrez						
Original						
Voting Statement: Xx						
Alastair Frew						
Original						
Voting Statement: xx						
Sridhar Sahukari						

Original						
Voting Statement: xx						
Garth Graham						
Original						
Voting Statement: xx						
Sigrid Bolik						
Original						
Voting Statement: xx						
Federico Rueda Londono						
Original						
Voting Statement: xx						
Marko Grizelj						
Original						
Voting Statement: xx						
Ireneusz Grzegorz Szczesny						
Original						
Voting Statement: xx						
Chandu Bapatu						
Original						

Voting Statement: xx						
Vicenç Casadevall						
Original						
Voting Statement: xx						

<u>Vote 2</u> – *Which option is the best? (Baseline, Original solution or WACM(s))*

Workgroup Member	BEST Option?
Mike Kay	
Tony Johnson	
Isaac Gutierrez	
Alastair Frew	
Sridhar Sahukari	
Garth Graham	
Sigrid Bolik	
Federico Rueda Londono	
Marko Grizelj	
Ireneusz Grzegorz Szczesny	
Chandu Bapatu	
Vicenç Casadevall	

6 GC0111: Relevant Objectives

Below set out how the Proposal meets the Applicable Grid Code Objectives as stated by the Proposer:

Impact of the modification on the Applicable Grid Code Objectives:	
Relevant Objective	Identified impact
(a) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity	Positive
(b) Facilitating effective 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;	Neutral
(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 Objectives	Identified impact
To permit the development, maintenance and operation of an efficient, coordinated and economical system for the distribution of electricity	Positive
To facilitate competition in the generation and supply of electricity	Positive

To 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;	Positive
To promote efficiency in the implementation and administration of the Distribution Code	Netural

Proposer's initial view:

The view of the Proposer is that GC0111 should be implemented without delay so that manufacturers are in no doubt about the necessary performance requirements for compliance with the RfG as implemented in GB.

7 Implementation

The current Grid Code and G99 are considered unclear in their treatment of fast fault current injection. As this change is deemed as clarification the Proposer seeks to implement this proposed modification following approval.

8 Legal Text

The WG concentrated on describing FFCI requirements in the Grid Code legal text, whilst keeping the needs of distribution connected plant in mind. When the Grid Code text became mature and generally accepted at the 13 February WG meeting, the new articulation of the requirements was transferred into G99. Because of the structure of G99 this needs changes to section 12.6 (for Type B Modules) and 13.6 (for Types C and D Modules).

Annex 3A details the proposed changes to the European Connection Code and European Compliance Processes should GC0111 be approved and implemented.

Annex 3B shows the proposed changes to sections 12.6 and 13.6 of G99.

Annex 1 – Terms of Reference

X

Annex 2A – Workgroup Presentation July 2018

x

Annex 2B – Workgroup Presentation September 2018

x

Annex 2C – Workgroup Presentation November 2018

Annex 2D – Workgroup Presentation December 2018

Annex 2E – Workgroup Presentation February 2019

Annex 3A – Grid Code Legal Text

Annex 3B – G99 Legal Text

