Grid Code Modifications H/04 & SA/2004

Responses to Ofgem's consultations 07/05 and 08/05

May 2005

Response to Consultation Documents

Proposed Grid Code Modifications H/04 and SA/2004
Supplementary Changes, January 2005

Section	Requirement	Response
CC.6.3.4	The Reactive Power output under steady-state conditions should be fully available within the voltage range +/-5% at 400kV, 275kV and 132kV and lower voltages, … (Only where Figure 4 cannot be applied.)	Export of reactive power corresponding to PF 0.95 leading at 105% voltage level at Grid Entry Point as required can result in excessive overvoltage at the generating unit terminals. It is assumed that the capability of exchange of reactive power in relation to the Grid Entry Point voltage level shall only be provided with the tap changer at the wind farm main transformer in an adequate position. This requirement has to be understood in connection with section CC.6.3.8 (c), where a continuously-acting automatic control system is required either at the Grid Entry Point or at the Generating Unit terminals. By using this control strategy, the reactive power exchange can be controlled by controlling the set point to the automatic voltage controller or by tapping the wind farm main transformer. Tapping of the wind farm main transformer will be required to fully comply with the requirements in CC.6.3.4. Further clarification of this item would be useful.

<u>Proposed Grid Code Modifications H/04 and SA/2004</u>
<u>Impact Assessment Jauary 2005</u>

<u>Response to the Impact Assessment:</u>

A full clarification of how existing non-synchronous generators and committed and planned non-synchronous generators will be affected by the proposed grid code modifications would be useful.

<u>GB Grid Codes, Extracts from Connection Conditions</u>
<u>Based on Rev. 3 – 29 November 2004</u>

Section	Requirement	Response
CC.6.3.2 (c), Figure 1	With all plant in service, the Reactive Power limits defined at Rated MW will apply at all Active Power output levels above 20% of the Rated MW output as defined in Figure 1.	Absorption of reactive power corresponding to PF 0.95 leading at 100% load down to 20% load will not be possible for direct connected induction generators without use of additional inductors.
CC.6.3.4	The Reactive Power output under steady-state conditions should be fully available within the voltage range +/-5% at 400kV, 275kV and 132kV and lower voltages, … (Only where Figure 4 cannot be applied.)	Export of reactive power corresponding to PF 0.95 leading at 105% voltage level at Grid Entry Point as required can result in excessive overvoltage at the generating unit terminals. It is assumed that the capability of exchange of reactive power in relation to the Grid Entry Point voltage level shall only be provided with the tap changer at the wind farm main transformer in an adequate position. This requirement has to be understood in connection with section CC.6.3.8 (c), where a continuously-acting automatic control system is required either at the Grid Entry Point or at the Generating Unit terminals. By using this control strategy, the reactive power exchange can be controlled by controlling the set point to the automatic voltage controller or by tapping the wind farm main transformer. Tapping of the

		wind farm main transformer will be required to fully comply with the requirements in CC.6.3.4. Further clarification of this item would be useful.
CC.6.3.7 (c) (iii)	Frequency control device deadband should be no greater than 0.03Hz (+/- 0.015Hz)	It is envisaged that a frequency control device with this sensitivity will be activated very often because of normal system frequency variations. Have the specific requirements been evaluated in connection with wind generation? And if so, what is the justification in terms of system stability for these deadband requirements?

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Date: 25 April 2005
Ref prj250405 GC H04

Mr Gareth Evans
Technical Advisor
OFGEM
9 Millbank
London
SW1P 3GE

For the attention of: **Mr Gareth Evans**

Re: GRID CODE CONSULTATION DOCUMENT H/04
Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors

Dear Gareth

Thank you for inviting ABB to comment on the above consultation document.

ABB welcomes the further clarification of the technical requirements for the connection of new generation technologies particularly with the prospect of a significant number of large windfarms requiring connections to the grid.

ABB is confident that the appropriate, commercially available plant and systems exist to facilitate the connection of many of the new generation technologies to meet these proposed technical requirements.

It should be noted that whilst these are technical requirements to ensure security of generation and system operation, they may well, in one form or another, become part of the contractual process between developers and equipment suppliers to facilitate some level of plant performance guarantee.

It is therefore essential that acceptable generic compliance procedures are established which can be used as part of the technical acceptance and contractual process.

Yours sincerely

Ian Funnell
General Manager
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AIRTRICITY'S RESPONSE TO THE CONSULTATION ON NGC'S GB GRID CODE DRAFTING INCORPORATING THE SA/2004 AND H/04 PROPOSALS, THE SUPPLEMENTARY CHANGES PROPOSALS, OFGEM'S IMPACT ASSESSMENT AND OFGEM'S 'MINDED TO' DECISION

Overview

Firstly, we wish to express our thanks for the opportunity to respond to the recent GB Grid Code consultation. Airtricity are an integrated renewable energy company with extensive development interests across the UK, Ireland and the United States of America. To date, we have successfully developed a number of wind farms in the Republic of Ireland (ROI) and UK, including the 24MW Ardrossan wind farm in Scotland, and have a number of large projects under development that will be impacted by this revised Grid Code.

Airtricity consider Grid Code changes enabling the integration of wind energy in to the GB Grid to be necessary. We understand that code amendments reflect the growing current and future importance of wind energy as a mainstream generation technology with a key role in contributing to security of supply and in dealing with the serious global threat posed by the current and historic greenhouse gas emissions from fossil fuelled generation.

From our direct experience in the ROI Grid and Distribution Code Review Panels and the Northern Ireland Wind Consultation Group we recognise the difficulties of formulating a revised Grid Code which considers both synchronous and asynchronous machines and appreciate the efforts of all those involved in formulating this latest draft.

Comments on the Proposals

Fault Ride Through

Airtricity recognise that the Transmission Licensees are required under their licences to promote the security of their transmission systems and that Fault Ride Through, the ability of a generator to remain connected to the grid and continue to generate when faults occur on the transmission system, is a generator performance characteristic desirable to achieve this. Additionally we understand that synchronous generators have a natural performance advantage over asynchronous machines in their ability to ride through faults and that additional performance specifications are required to capture this discrepancy.

We have considered the proposed requirements for the recovery of active power after a fault and note that the need or justification for such a rapid recovery of real power on the system does not appear to have been demonstrated. In addition, we consider the conditions to be considerably more onerous than those required in Germany and Denmark and that many turbine manufacturers have not developed the designs necessary to achieve such requirements.

Given the large capital cost of complying with this clause we feel that further study, quantifying the degree of ride through required, should be carried out before imposing requirements of this severity. Additionally we would propose that any implementation of the more demanding and onerous active power recovery times be delayed so as not to prejudice the completion dates of the projects in development at the current time.

With regards to threshold for FRT capability, we request due consideration be given to the BWEA's proposal that the requirement should apply only to wind farms operating at 50MW or greater output.

In connection conditions CC.6.3.15 (a)(ii) and CC.6.3.15 (b)(ii) we consider the word *maximum* shall refer to the ability of the installed equipment and control systems to increase/decrease reactive output/reactive demand within it's actual design capability and shall not be taken to mean meeting any specific quantities, rates etc. specified elsewhere in the Grid Code.

We believe due recognition is required to be given to the effect of changing wind speed during an event such as a voltage dip, fault or frequency change and hence the active power output of a wind farm prior to and following such an event.

We note the proposed Grid Code changes will impact the Transmission Licensees and Distribution Network Operators with respect to the provision to developers of information beyond that presently required (eg supergrid protection settings). We also note that resources within the TLs and DNOs are presently stretched and that additional workload may lead to delay in the provision of information and hence to the development of renewable generation projects. We consider that where provision of such information is delayed the developer should be expected to make reasonable assumptions in order to maintain the progress of their projects and that Ofgem should grant reasonable derogations where such reasonable assumptions result in plant not meeting the requirements of the Grid Code.

Frequency Range

Airtricity appreciate that the Scottish Grid Code and England and Wales Grid Code already require generators to be able to operate at frequencies above and below the nominal 50 Hz to ensure that generation is able to continue to contribute towards meeting demand in exceptional operating circumstances.

We do not consider the application of this requirement to asynchronous generators to be a contentious issue and understand that wind turbine manufacturers have confirmed that their equipment can meet this requirement.

Frequency Control

Airtricity consider that, at current penetration levels of asynchronous generators on the system, the capability of such generators to provide frequency control to the grid is not essential and that timescales for implementing any such requirements should be adjusted accordingly.

We consider any requirement to provide high and/or low frequency response to be presently commercially undesirable.

We acknowledge high frequency response capability can be achieved by wind energy but at current penetration levels we do not believe this requirement should be implemented.

We understand the method by which a low frequency response service from wind energy could be implemented has to date not been demonstrated. We consider NGC should be required to provide suitable demonstration of the capability of wind energy to provide low frequency response capability prior to any consideration being given to the drafting of appropriate Grid Code wording, setting of thresholds or implementation of any such requirement.

Reactive Range and Voltage Control

Airtricity recognise the control of system voltage within the statutory limits requires that sources of reactive power are available across the system at various voltage levels and that generating plant has traditionally been the preferred source of reactive power.

We accept that asynchronous generators should be capable of providing reactive power to the grid and would add that they should be remunerated for this ancillary service in the same manner as conventional plant.

We consider:

- In order to comply with the reactive power requirement as defined in the proposed Grid Code changes that additional capacitive compensation would be required to allow reactive power to be exported from the asynchronous generator onto the network as the amount of reactive power an asynchronous generator absorbs from the network increases as its output power increases.
- For the asynchronous generator to absorb the same amount of reactive power at 20% active power output as at 100% active power output, and hence achieve compliance with the proposed GB Grid Code, extra inductive compensation may be necessary to attain the reactive power characteristic proposed by NGC.

We recommend the GB Grid Code follow the requirements relating to reactive range and voltage control set out in the ESB Grid Code and outlined in the SKM report "New Generation Technologies and GB Grid Codes – Report on Change Proposals to the Grid Codes in England and Wales and in Scotland". We consider the GB Grid Code reactive requirement characteristic should recognise the asynchronous generator P/Q characteristic between 20% and 50% of its active power output and that the proposed requirement be modified accordingly (ie as per the ESB Grid Code the relaxation in the reactive power output requirement should start for active power outputs below 50% as opposed to the 20% proposed by NGC). For the reasons outlined above, additional reactive plant would be required to achieve the NGC proposed output requirements and we consider the justification for the cost associated with this additional equipment, which would adversely impact project economics, does not appear, too date, to have been demonstrated by system need.

We are also concerned that the approach proposed by NGC can lead to inconsistency in the reactive output requirement of an asynchronous generator when extended to the operation of a wind farm as a whole (for example, consider the situations i) where 100% of the wind farm generator units are operating at 25% active power output and ii) where 50% of the wind farm generator units are operating at 50% active power output. If the reactive power output requirement as proposed by NGC is applied to these cases it can be demonstrated that for case i) the individual generating units operating would be required to produce double the reactive power output as for case ii)). The example outlined demonstrates that the generator units would be required to provide different levels of reactive power output for the same active power output.

To avoid impact on projects presently close to entering construction we propose the reactive range/voltage control requirements as proposed by Airtricity above not be implemented for wind farms with energisation dates before 1st January 2007.

Thresholds

Airtricity note the definitions of Small, Medium and Large Power Stations are different in all three transmission licensee areas and welcome that a number of thresholds have been specified on a MW basis within the Grid Code.

We also support the alternative drafting which has been produced and included in the Supplementary Changes, which extends the GB Grid code exemption for Small Power Stations to Scotland.

We note the timescales proposed for the introduction of the SA/2004 requirements differ from the equivalent H/04 proposals and strongly request due consideration be given to the timescales and thresholds set out in our above comments relating to Fault Ride Through, Frequency Control and Reactive Range and Voltage Control.

Ramp Rates

Airtricity consider the removal of the proposed ramp rate requirement in Scotland to be a very positive consequence of the change to a GB code. We believe if such a requirement had been incorporated this would have significantly reduced wind farm efficiency and increased costs to consumers.

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> -----Original Message-----
> From: Greig, Elaine
> Sent: 24 February 2005 13:36
> To: 'gareth.evans@ofgem.gov.uk'
> Cc: 'BWEA Richard Ford'
> Subject: Grid Code consultation
>
> Gareth,
>
> As you are aware I have contributed previously to this debate. In
> this round of the consultation I have fed my views through the BWEA,
> and therefore fully endorse the response that they have already sent
> to you.
>
> Regards,
>
> Elaine Greig
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AREVA

Mr. Gareth Evans
OFGEM
9, Millbank
SW1P 3GE
London

27th February 2005

Dear Sirs,

GRID CODE CONSULTATION H/04
GRID CODE CONSULTATION SA/2004

We refer to Mr. J. Scott's letters dated 17th January inviting comments on the proposed changes to the England and Wales and Scottish Grid Codes.

We have no comments on the proposed codes or wording used. We note however that Section 7 of the Impact Assessment estimates an increase in cost of up to 6% in meeting the new codes.

With respect to large DC interconnectors the cost impact of satisfying the reactive power requirement of the proposed codes may be significantly higher than 6%. For a conventional HVDC station, we estimate an increase in cost of up to 20%, which could seriously affect the financial viability of any scheme.

We would suggest there may be a case for exempting any future large DC interconnectors from the need to mimic a synchronous machine on the basis that there is already sufficient existing and planned reactive power control within the English, Welsh and Scottish systems to avoid the need to provide independent control from future DC interconnectors.

Yours faithfully

G. N. Graham
Business Development Manager
AREVA T&D Ltd

Econnect

BWEA Grid Code Representation

BWEA response to

Grid Code Consultation H/04 and SA/2004 and Ofgem Regulatory Impact Assessment

Econnect Project No: 1294

Prepared For	BWEA Renewable Energy House 1 Aztec Row Berners Road London N1 0PW

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1	Richard Ford	BWEA
2	Econnect (Client File)	Econnect Ltd
3	Econnect (Project File)	Econnect Ltd

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1 Introduction

This document includes the BWEA response to the Ofgem consultation, which comprises a number of documents.

1) Ofgem Letter "Grid Code Consultation H/04" 17th January
2) Ofgem Letter "Grid Code Consultation SA/2004" 17th January
3) Ofgem's "Proposed Grid Code Modifications H/04 and SA/04 - Supplementary Changes" January 2005 (these changes apply to the GB Grid Code)
4) Ofgem's "Proposed Grid Code Modification H/04 and SA/2004 Impact Assessment (IA)" January 2005
5) SKM report "New Generation Technologies and GB Grid Codes" December 2004.
6) Drafting changes for GB Grid Code/

http://www.nationalgrid.com/uk/indinfo/grid_code/pdfs/GB_Text_Extracts_050105.pdf

The response is structured as follows:

Section

2. Overview.
3. Process Principles
4. Modifications and additions to proposals
5. Qualifications to proposals
6. Response to Impact Assessment.
7. Response to SKM report.
8. Detailed Grid Code Clause changes.

The response has been developed in consultation and with input from several BWEA members. Following the issue of the consultation it was reviewed and an original first document of comments was circulated. A meeting of members was held to review that first document. Following this meeting a more detailed response was developed incorporating issues raised and discussed at the meeting. This second document was circulated to members for comment. In the meantime detailed Grid Code clause changes were developed to reflect the second document and further comments by members. This document is the final document with these comments taken into account.

1.1 Summary of key points

- Retrospective implementation of Grid Code changes for any reason is unacceptable.
- Implementation dates must allow time for technology development.
- There is minimal risk to system of delays as all projects approaching completion are reported to have similar requirements in bilateral agreements.
- Ofgem's Impact Assessment has not considered the impact of delaying wind energy. A small delay will increase CO_2 emissions and costs to the consumer.

2 Overview.

The BWEA believes that Grid Code changes for Wind Energy are necessary and that they reflect the growing current and future importance of wind energy as a mainstream generation technology with a key role in the future security of supply and in dealing with the serious global threat posed by the current and historic greenhouse gas emissions from fossil fuelled generation.

The BWEA recognises the hard work put in by a number of people over several years to develop appropriate Grid Code changes in Scotland, England and Wales. The BWEA particularly welcomes the development of a single set of proposals for the synchronous system of Great Britain and the efforts of Ofgem and the Transmission Licensees to achieve this. One very positive consequence of this change to a GB code is the removal of the proposed ramp rate requirement in Scotland, which, if activated, would have significantly reduced wind farm efficiency and pushed up costs to consumers.

The difficulties of achieving a revised Grid Code reflect fundamental differences between fossil fuelled synchronous generation and wind energy using asynchronous machines. Whilst it is feasible to develop a set of rules and requirements (a Grid Code) for either technology to provide a "level playing field" for the generators with that technology, it is much more difficult to create a single set of rules that encompass both technologies. The BWEA therefore welcomes the recognition by Ofgem that market based solutions are the preferred options for addressing these differences in the future.

The BWEA appreciates that developing the Grid Code requirements is a very difficult process especially where the current requirements are assumed, but not clearly specified (e.g. for fault ride through), and where a specification now has to be developed covering not only wind energy but also DC interconnectors and new synchronous generating plant.

The BWEA therefore welcomes the approach taken by Ofgem in organising the Forums, employing consultants to provide additional advice and in carrying out the first Impact Assessment for a Grid Code change. The Forums organised by Ofgem have played a key role in improving clarity and consistency by developing an enhanced understanding of the issues for generators and transmission licensees.

Econnect

3 Process Principles

3.1 Implementation timing

The BWEA is concerned that some of the changes are being proposed retrospectively and some without sufficient notice. As a matter of principle the BWEA understands that any Grid Code change, which acts retrospectively or has an implementation date that affects projects under construction (which also means those which have been financed, designed and tendered) has a potentially significant impact on the financial assumptions and procurement processes of major project investments and therefore could be seen as anti-competitive.

The BWEA recognises that the changes have been discussed and developed over a long period of time and that some generators have signed bilateral agreements with transmission licensees that contain conditions that may be closely aligned to many of the proposed changes. However, these bilateral agreements are not in the public domain, so the conditions cannot be compared with the latest Grid Code changes. In addition most of the projects that have signed Bilateral Agreements with additional conditions have not yet started construction, and so the capabilities have yet to be demonstrated in commissioning tests.

As so many, if not all projects in the pipeline have bilateral agreements with additional connection conditions, later implementation of Code changes will not have an impact on the security of the transmission system or impose additional costs on users.

BWEA also recognises that there is a huge quantity of connection applications in the pipeline. BWEA believes that given the gestation period for projects and the delays in planning permissions and in gaining transmission access, (which may be dependent on transmissions reinforcements), the timings proposed by BWEA will not result in any adverse impact on security of the transmission system or impose additional costs on users.

BWEA notes that Ofgem is minded to accept NGC's case for capacity and timescale thresholds[1]. Ofgem however has not commented on NGC's record in estimating rates of development. In NGC's Generic Provisions proposals of June 2003,**[GN1]** NGC estimated that in 2006 there would be 1.6GW of Round 1 offshore wind farms and 4GW of Round 2 wind farms commissioning[2]. At the time of writing only 120MW or 2% of this estimate is commissioned or commissioning. Econnect, on behalf of the BWEA, has estimated that by the middle of 2006 this total is likely to be 516MW or 9% of the estimate and a maximum of 15% of the estimate by the end of 2006.

	NGC estimate MW 2006	**BWEA estimate MW 2006**	**Actual Feb 2005**
Round 1 offshore	1600	516 to 840	120
Round 2 offshore	4000	0	0
Total	5600 (100%)	<840 (15%)	120 (2%)

Figure 3.1a Estimated and actual wind capacity commissioning

[1] Ofgem's H/04 letter Page 7 Section vi) Thresholds.
[2] NGC information paper sections 14 and 15.

Ofgem considers that the change proposals will not affect the growth of wind and cites the rate of applications for connection of wind farms as evidence[3]. We suggest that Ofgem considers the previous policy instrument the NFFO contracts in relation to wind energy development. In 1998 following a due diligence and assessment process by electricity industry regulator 60 wind energy contracts were awarded totalling an installed capacity of 840.4MW. Seven years later there were only 9 of those projects connected totalling 17.3MW installed capacity or 2.1% of the capacity awarded[4].

	NFFO5 wind capacity let 1998 MW	**NFFO5 wind capacity built 2005 MW**
Total	840 (100%)	17.3 (2.1%)

Figure 3.1b NFFO Contract wind capacity

BWEA therefore has proposed a revised timetable for the introduction of the new requirements and believes that a speedier introduction of the requirements would be disproportionate.

The BWEA includes drafts of relevant clauses with changes to the dates to avoid retrospective changes.**[GN2]**

[3] Ofgem Impact Assessment Section 6.35
[4] Data taken from www.nfpa.co.uk at time of writing. Capacity derived from DNC data with 0.43 scaling factor.

3.2 Presumption of no material impact

The BWEA is concerned that Ofgem are diluting the consultation process and setting a dangerous precedent. In the IA Ofgem state:

"For parties currently negotiating connections, it is Ofgem's understanding that all such parties have been informed by the licensees that connection offers will be based on the SA/2004 or H/04 proposals. If Ofgem's final decision approves these proposals there should therefore be no material impact on the parties currently negotiating connections."[5]

Firstly, as the offers and agreements made are not in the public domain the BWEA cannot ascertain whether these offers are the same as the current proposals, therefore no judgement can be made on the material impacts on the users. As an example, the original Scottish proposals and Wind farm Connection Guide**[GN3]** on which a lot of connection offers are based did not have <u>any</u> requirements for rate of active power recovery post fault. These latest proposals have far more onerous requirements for active power recovery post fault than both the EoN and the Danish Grid Code requirements.

Secondly, it sets a precedent that if in future a licensee gives notice of a change to users, the users "have been informed". It does not follow however that there will be no material impact on those users of that change. The implication is that licensees can change connection requirements outside the normal consultation process by serving notice in advance on users as a fait accompli. BWEA believes this is an unacceptable precedent and is outside the remit of Licensees and Ofgem.

[5] Ofgem Impact Assessment Section 6.13.

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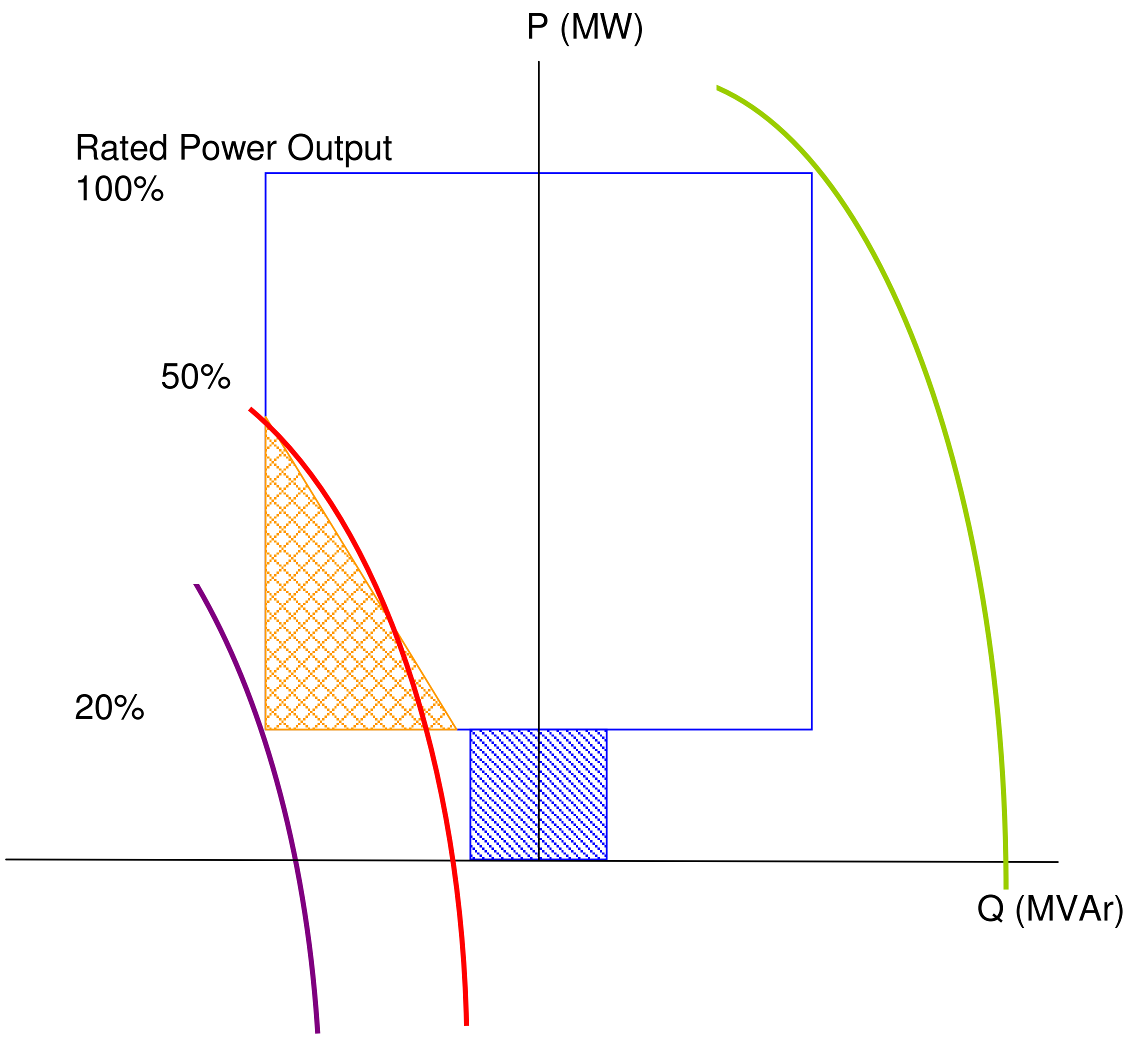
4 Modifications & additions to proposals.

BWEA has carefully considered the proposed Grid Code changes. For each change the factors considered have been:

- The wording or the relevant clause.
- The interaction of the clause with other relevant clauses.
- The ability to successfully interpret the clause and definitions for wind energy.
- Up to date experience in the UK and Ireland in the design, procurement and specification of wind farms with Grid Code requirements similar to those proposed.
- The difference between UK and European Grid Codes and the materiality of these differences.
- The ability to define and assess compliance with requirements in advance of financial closure of a project.
- Materiality of the issue to GB system.
- Any costs imposed on other users or licensees.
- The potential impact on adjacent and subsequent wind farm developments.
- The limited technical resources available in the manufacturing, developer and network operator businesses and therefore the capability to effectively implement the changes in the proposed timescales.

4.1 Reactive power envelope



Asynchronous generator P/Q characteristic uncompensated

Asynchronous generator P/Q characteristic with additional capacitive compensation

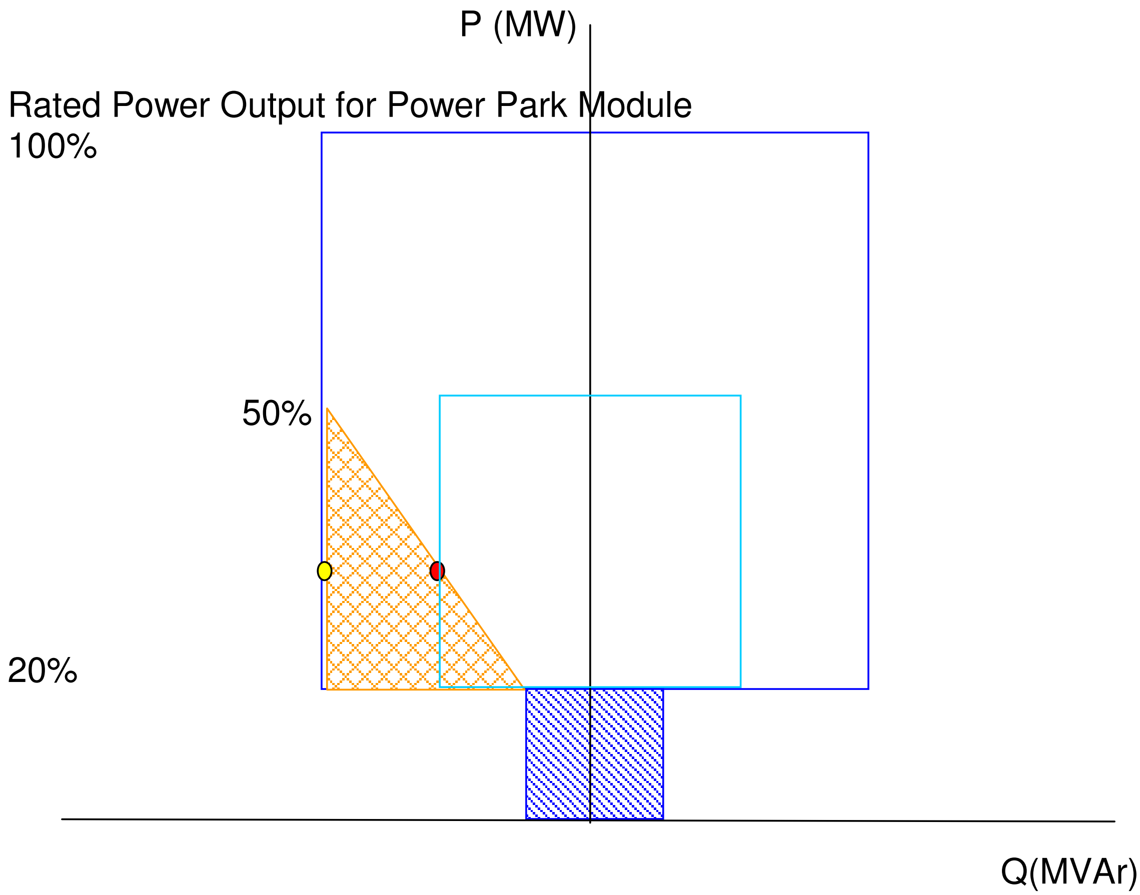
Asynchronous generator P/Q characteristic with additional inductive compensation

Reactive Power Requirement Characteristic (As defined in NGC H/04 Grid Code Changes to Incorporate New Technologies Consultation)

Area of Characteristic Asynchronous generator is unable to meet without additional INDUCTIVE compensation equipment.

4.1a Power Park Unit Reactive Power Envelope

The amount of reactive power an asynchronous generator absorbs increases as its output power increases (as shown by the red characteristic in Figure 4.1a). Therefore additional capacitive compensation is required to allow reactive power to be exported from the wind farm onto the network, in order to comply with the reactive power requirement as defined in the proposed Grid Code changes. However, the shape of the proposed reactive power requirement characteristic (Figure 1 in CC6.3.2 (c)) also means that extra INDUCTIVE compensation may be required in order for the wind farm to be able to absorb the same amount of reactive power at 20% active power output as it does at 100% active power output. It is the BWEA's opinion that the cost of this extra reactive equipment is not justified by a system need. Hence the BWEA recommends that the proposed GB Grid Code reactive requirement characteristic be amended to account for the P/Q characteristic of the asynchronous generator between 20% and 50% of its active power output (as defined by the removal of the hatched triangle in Figure 4.1b). Such an amendment would bring the GB Grid Code into line with the reactive requirement in the ESB Grid Code in Ireland.



Reactive Power Requirement Characteristic (As defined in NGC H/04 Grid Code Changes to Incorporate New Technologies Consultation)

Area of Characteristic Asynchronous generator is unable to meet without additional INDUCTIVE compensation equipment.

Reactive Power Requirement Characteristic for 50% of Power Park Units within Power Park Module in operation (As defined in NGC H/04 Grid Code Changes to Incorporate New Technologies Consultation)

Figure 4.1b Power Park Module Reactive Power Envelope

If this amended reactive requirement is extended to a power park module as a whole, it can be seen from Figure 4.1b that the same reactive power output is achieved for 100% of the Power Park Units (PPUs) operating at 25% of active power output, as for 50% of the PPUs operating at 50% of their active power output (indicated by the red dot).

The original reactive requirement characteristic however calls for 100% of the PPUs operating at 25% of their active power output to produce double the reactive output of the scenario where only 50% of the PPUs are operating at 50% of their active power output (indicated by the yellow dot). This methodology is inconsistent as it calls for different levels of reactive power output from the power park module for the same active power output.

The BWEA proposal will not therefore have any impact on investment costs as the transmission system operator would already have to design the network for the lower reactive power capabilities of the windfarm with some PPUs not operating.

The BWEA includes the drafts of relevant clauses with changes to the dates to avoid retrospective changes in Section 8.**[GN4]**

- CC 6.3.2 (c) Figure 1 amended
- CC 6.3.2 (d) remove due to retrospective applications
- CC 6.3.2 (new d) new clause describing requirements below 20% of rated power

4.2 FRT Active power recovery

BWEA has carefully considered the proposed requirements for the recovery of active power after a fault. It is noted that:

- No requirements for active power recovery were included in the original Scottish proposals SB/2002 and Guidance Note tabled in December 2002[6]
- No system need or justification for such a rapid recovery of real power has been tabled or demonstrated.
- The provisions are much more onerous than those in Germany or Denmark.
- These are recent requirements and many turbines have not yet developed the design strategies necessary for delivery (assuming such a development is possible).

BWEA notes that the EoN requirements have 3 possible rates for active power recovery:

- 20% per second for a small voltage dip;
- 5% per second for a severe voltage dip;
- 10% per second following reconnection if the turbine is disconnected and reconnected within 2 seconds.

BWEA proposes following the EoN requirements for active power recovery with a minimum rate of recovery of 10% of installed active power per second (but notes there is no option in GB Code for disconnection and reconnection).

BWEA proposes that the implementation of the more demanding and onerous active power recovery times of 0.5 to 1s is delayed, so as not to prejudice the completion dates of the projects in development at the current time.

The BWEA includes drafts of relevant clauses with changes as noted.**[GN5]**

- CC 6.3.15 (a) (ii) modified to incorporate 10% recovery rate.
- CC 6.3.15 (b) (iii) modified to incorporate 10% recovery rate.
- CC 6.3.15 (a) (iii) included incorporating the rapid active power recovery from 1 April 2007.
- CC 6.3.15 (b) (iv) included to incorporate the rapid active power recovery from 1 April 2007

[6] S&SE and SP Guidance Note for the Connection of Wind Farms Issue No .2.1.4.

4.3 FRT No turbines operating

The BWEA made an earlier proposal to limit the fault ride through requirements to any time when less than 50% of the turbines are operating by modifying clause CC.6.3.15. (b)(ii). BWEA has reviewed SKM's response and as a result the BWEA has reconsidered its proposals.

This section explains the problem in this area and considers two solutions and makes a proposal for a solution.

Consider a windfarm connection with a simplified design shown in figure 4.3A.

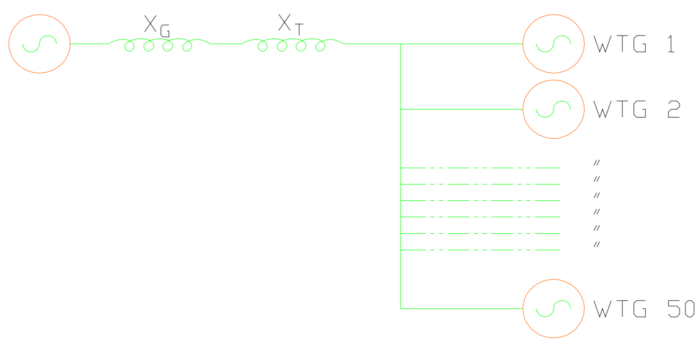


Figure 4.3a simplified windfarm single line diagram

Figure 4.3a represents a windfarm of 50 turbines. The impedance Xg determines the fault level at the point of connection. The impedance Xt represents the grid transformer and the turbine transformers and is selected with a high enough value to provide sufficient retained voltage on the generator terminal in the event of a grid fault. However, the impedance Xt cannot be infinite due to costs, voltage regulation and the losses generated in the associated resistance. Figure 4.3b shows the effects of a grid fault with the whole windfarm operating

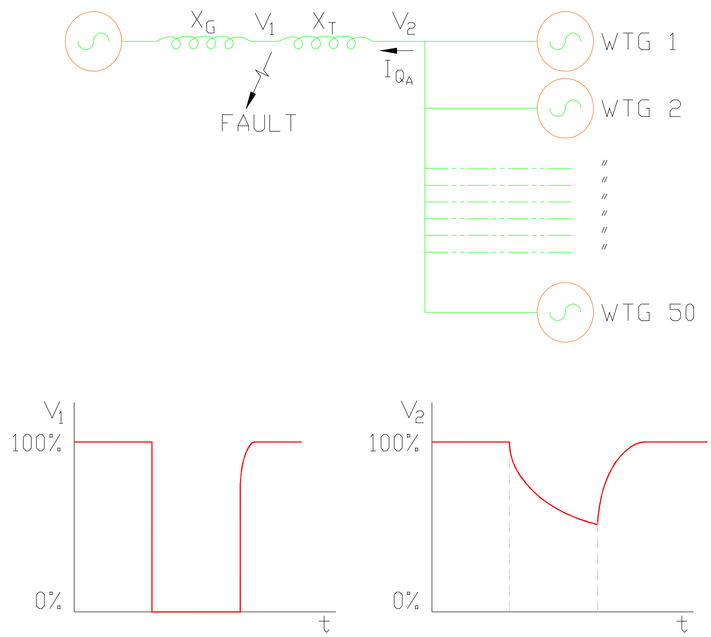


Figure 4.3b Grid Fault with all turbines operating

Figure 4.3b shows the voltage at the fault, V1, falling to zero for a short duration until the fault is cleared. The voltage at the generator terminals, V2, falls more slowly due to the reactive current IQA supplied, for example, by the demagnetisation of the generators. In this example the voltage V2 remains sufficiently high due to the impedance Xt and the fault current IQA to allow the generators to ride through the fault.

To emphasise the point in this example Figure 4.3 c assumes that only one wind turbine is connected. However the same principles apply for any example where not all the turbines are connected.

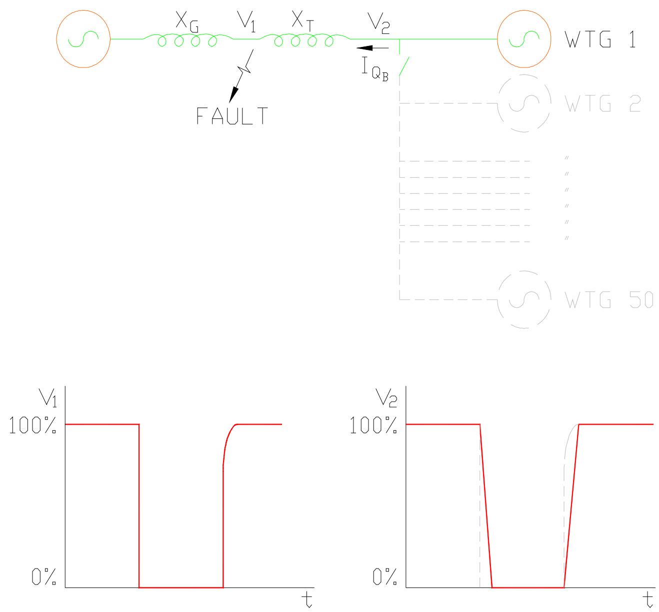


Figure 4.3c Grid Fault with one turbine operating

Figure 4.3c shows the impact when fewer turbines are connected during the fault and in this case only one turbine is connected. The voltage profile at the fault, V1, is effectively unchanged. However, the voltage at the generator terminals, V2, has now fallen (in this example to zero), as the reactive current IQB is now 1/50th of its previous value whereas the value of the impedance Xt is unchanged. The voltage V2 is now no longer high enough to allow the generator to ride through the fault.

The example shown in Figures 4.3 demonstrates that a design limit for FRT is required. The number of generating units connected, and not the real power output of the windfarm determine this limit.

Removing the requirement for wind farms to ride through when less than 50% of the turbines are operating provides a design limit, which can generally be achieved without excessive additional costs.

The BWEA therefore supports the proposed wording in main consultation for Clause 6.3.15 (c) (i) and does not support Option 2.

4.4 FRT Voltage Measurement Point

Option 4 in Ofgem's consultation includes extra wording in clause CC.6.3.15 (b)(ii) and (iii) which include reference to the User System Entry Point . The BWEA supports this Option 4 with a slight modification. Other clauses also refer to the User System Entry Point. This is the point at which an embedded generator connects to the Distributed Network Operator network. However, where a generator connects to the 132kV system in Scotland this would not be a User System Entry Point, nor would the Supergrid Voltage be measured at this connection point.

BWEA therefore proposes changing the wording to cover the 132kV connection in Scotland for all relevant clauses**[GN6]**.

- CC 6.3.2 (c) The term **Grid Entry Point** is used and wording has been deleted so that it applies to all transmission connected users.
- CC 6.3.15 (b) (ii) the term **Grid Entry Point** has been used instead to be consistent with CC6.3.2.(c).
- CC 6.3.15 (b) (iii) the term **Grid Entry Point** has been used instead to be consistent with CC6.3.2.(c).
- CC 6.3.15 (b) (iv) the term **Grid Entry Point** has been used instead to be consistent with CC6.3.2.(c).

4.5 Backup Protection and Negative Phase Sequence

Clause CC6.3.15 (c) (ii) appears to be a remnant from the specifications on synchronous machines, which has not been duly considered in relation to the revised requirements. As all the requirements for fault ride through are now specified in detail in CC6.3.15 (a) and (b) this clause is now superfluous. The prior clauses already require the negative phase sequence capability and clearly specify how fault clearance times are to be calculated.

BWEA has therefore:

- deleted Clause CC6.3.15 (c) (ii).

4.6 Frequency Response

The BWEA has carefully considered the proposal for Frequency Response. It is noted that

"Ofgem is minded to recognise that non-synchronous generators should be able to provide a frequency control capability to the grid. While this is not essential at current penetration levels."[7]

BWEA has taken account of:

- The ability to successfully interpret the requirements, clauses and definitions for wind energy.
- Up to date experience in the UK and Ireland in the design, procurement and specification of windfarms with Grid Code requirements similar to those proposed.
- The difference between UK and European Grid Codes and the materiality of these differences.
- The ability to define and assess compliance with requirements in advance of financial closure of a project.
- Materiality of the issue to GB system.
- Any costs imposed on other users or licensees.
- The limited technical resources available in the manufacturing, developer and network operator businesses and therefore the capability to effectively implement the changes in the proposed timescales.

As a result the BWEA considers that the risks of delaying current wind energy developments (as illustrated in Section 6) through the implementation of this clause forthwith far outweigh the costs or risks to the system or users. The BWEA therefore proposes a delay of one year prior to implementation of this clause (with a further one year timescale for implementation in projects).

The BWEA proposes that this implementation date should only be maintained if a documented demonstration of the capability is provided by NGC in association with a willing generator. There is concern at present that the methodology for implementing this service from wind energy has not been demonstrated and therefore drafting Grid Code wording in advance of such an understanding is a meaningless exercise.

In the meantime BWEA accepts that wind turbines can operate in **Limited Frequency Sensitive Mode** as defined in CC6.1.3. (f) (iii).

The BWEA includes drafting of relevant clauses with changes to the dates and thresholds to avoid retrospective changes and ensure consistency. Also including changes to the wording and definitions to provide clarity for wind power.**[GN7]**

- CC.6.3.7 (a) Modified to apply to Power Park Modules with completion after 1 April 2007 with a capacity of 100MW or more.
- CC.6.3.7 (e) (i) Modified to apply to Synchronous Generating Units not all Generating Units.

[7] Ofgem consultation letter Section iii) page 6.

- CC.6.3.7 (e) (iii) Modified to apply to Power Park Modules with completion after 1 April 2007 with a capacity of 100MW or more.
- CC.6.3.7 (e) (iv) Modified to apply to Power Park Modules with completion after 1 April 2007 with a capacity of 100MW or more.
- CC.6.3.7 (f) (i) Modified to apply to Synchronous Generating Units not all Generating Units.
- CC.6.3.7 (f) (iii) Modified to apply to Power Park Modules with completion after 1April 2007 with a capacity of 100MW or more.
- CC.6.3.7 (f) (iv) Modified to apply to Power Park Modules with completion after 1 April 2007 with a capacity of 100MW or more.

4.7 Frequency Range

BWEA agrees that this capability can be achieved by wind energy.

The BWEA includes drafts of relevant clauses with changes to the dates and thresholds to avoid retrospective changes and ensure consistency.**[GN8]**

4.8 Island Mode

The BWEA reiterates its proposal and notes the SKM's supporting recommendation to remove clause CC 6.3.7 (c) (i).

- CC 6.3.7 (c) (i) modified so that it does not apply to Power Park Modules.

4.9 Availability Definition

To avoid ambiguity in proposed clause BC.1.A.1.8.3, BWEA has modified the clause to make it clear that just because a wind turbine is available it is not necessarily running. Whether it is running or not depends on the available wind resource.

The BWEA includes a draft of this definition.**[GN9]**

- BC.1.A.1.8.3 reworded.

4.10 Timescales

The BWEA has considered each change of requirement individually. Each requirement has been assessed to determine the anticipated lead-time required to implement that change.

The absolute minimum lead-time is nine months, which gives just enough time to specify additional off the shelf equipment to meet a construction program deadline. This minimum lead-time can only be achieved where there is:

- A choice of supplier.
- Off the shelf designs.
- No implications for the specification of major long lead-time plant (e.g. wind turbines or grid transformers).

- No development requirements.
- Existing test data and experience to demonstrate and prove capability.
- No significant impact on project costs or risks.

Where any these conditions do not apply a lead-time in excess of 9 months is required.

Each requirement is considered in turn in the following subsections.

4.10.1 Steady state Voltage and reactive power

The BWEA's proposed steady state voltage requirements meet the minimum lead-time criteria stated above:

1st January 2006.

4.10.2 Limited Frequency Sensitive Mode

The Limited Frequency Sensitive Mode requirements can be met with the minimum lead-time criteria stated above.

4.10.3 Frequency response

The frequency response requirements will take 12 months to develop and demonstrate with additional grid code wording developments as a result and a 12-month project lead in time. The BWEA notes that Ofgem have recognised this as a lower priority requirement.

1 April 2007.

4.10.4 FRT – EoN active power recovery

The modified active power recovery requirements proposed by the BWEA (based on EoN's requirement for active power recovery) will required a 12 month project lead in time.

1 April 2006.

4.10.5 FRT - fact active power recovery

The rapid active power recovery requirements proposed in the consultation will require 12 months to develop and demonstrate with a 12 month project lead in time.

1 April 2007.

The BWEA includes drafts of relevant clauses with changes to the dates to avoid retrospective changes.**[GN10]**

4.11 Capacity Thresholds

The BWEA has carefully considered how thresholds should be set to ensure that:

- Differences in transmission voltage between Wales, England and Scotland are taken into account.
- The need to develop a secure and efficient transmission system is acknowledged.
- Competition in generation on the GB transmission system is neither prevented nor restricted.

BWEA notes that a number of thresholds have been specified on a MW basis within the Grid Code so that the classification of power stations as Small, Medium or Large becomes irrelevant. BWEA strongly supports this approach as it provides stability and clarity of requirements.

4.11.1 Steady State Voltage and Reactive Power

Owing to the differences in Scotland, BWEA accepts that a 5MW threshold is appropriate for Scotland and a 50MW threshold is appropriate in England and Wales.

4.11.2 Limited Frequency Sensitive Mode

The frequency of the system, and its control, following a fault is the same in all parts of the GB system. Therefore there must be one GB threshold for high frequency response.

BWEA proposes that this threshold is 50MW.

4.11.3 Frequency response

The frequency of the system, and its control, following a fault is the same in all parts of the GB system. Therefore there must be one GB threshold for low frequency response. BWEA is concerned that delays to project completion may occur by imposing a low threshold for this capability, without there being any immediate benefit to the system, or other users, to justify such a low threshold.

BWEA proposes that this threshold is 100MW.

4.11.4 FRT

The propagation of faults on the GB system takes no account of boundaries or of the classification of assets as transmission or distribution. Therefore there must be one GB threshold for FRT requirements.

BWEA proposes that this threshold is 50MW.

The BWEA includes drafts of relevant clauses with changes to the dates to avoid retrospective changes.**[GN11]**

5 Qualifications to Proposals

The BWEA will accept certain aspects of the proposals on the proviso that Ofgem makes a clear statement on the interpretation of key aspects of the changes.

Through the Grid Code Forums organised by Ofgem the BWEA has understood the intention and meaning of a number of the requirements. Some of the Grid Code changes have been worded in a way that leaves them open to interpretation. In many cases this is a positive outcome as it recognises that the technology and Grid Code specification are still under development. The BWEA is however concerned that once the changes are in place some parties may chose to interpret ambiguities in a particular way which may result in unintended delays in wind development, the consequences of which have not been considered in the Impact Assessment.

5.1 FRT "maximum" reactive power

BWEA proposes that in its decision document Ofgem should state:

The word "maximum" in connection conditions CC.6.3.15 (a)(ii) and CC.6.3.15 (b)(ii) shall mean that the control systems shall be designed to increase the reactive output of the equipment or decrease the reactive demand of the equipment allowing for the physical design of the equipment and the capabilities of the control systems employed. It shall not be interpreted to mean meeting any particular quantity, rate or limit of reactive power or current specified in other parts of the Grid Code or in other documents."

BWEA notes that the de-magnetisation and re-magnetisation currents will be determined by the sub-transient and transient responses of the wind turbines and other electrical plant within the windfarm power collection system.

5.2 FRT Embedded plant and data

BWEA proposes that in its decision document Ofgem should state:

"Ofgem recognises that the proposed Grid Code changes require the provision of additional information from the Transmission Licensees (TL) to applicants in the form of Supergrid Protection Settings and other data (including data on Distribution Network Operators (DNO) networks and Distributed Generation for embedded plant) in order that prospective generators can design and specify their equipment to meet the Grid Code Fault Ride Through requirements. This provision of data, which is additional to data previously provided, has the potential to delay the development of specific wind energy projects, and wind energy developments in total, causing an adverse impact on CO_2 emissions and costs to the consumer. Ofgem will not tolerate delays by TL or DNO in the provision of such data. Where the provision is delayed, Ofgem expects that generators may chose to make reasonable assumptions in order to progress their projects. Where these reasonable assumptions result in plant not meeting grid code requirements, Ofgem will grant reasonable derogations from the requirements.

Ofgem expects that wherever practicable, relevant data should be published in the seven year statements and the LC25 long term development statements by the TL and DNO."

BWEA notes that the transmission licensees staff are stretched in dealing with their day jobs plus the additional work required in providing and processing connection applications and enquiries. In Section 6 of this document BWEA have demonstrated the potential cost to the consumer and additional CO_2 emissions caused by delays in wind energy implementation.

5.3 FRT and Frequency response – wind speed changes

BWEA proposes that in its decision document Ofgem should state:

"When assessing the active power output of a windfarm before and after an event, such as a fault, voltage dip or frequency change, due recognition must be given to the potential effects of changing wind speeds during the event and the resulting changes in power output. It is impossible for any system to accurately measure this effect during any single event. It is possible to utilise statistical techniques to assess the probability of the response of the windfarm meeting a defined criteria and the certainty of the assessment will increase with an increasing number of events."

BWEA notes that an anemometer is a spot measurement of windspeed whereas a wind turbine (and even more so a windfarm) is capturing wind energy over the whole swept area of the rotor(s). In order to measure the power output of a wind turbine to international standards **[GN12]**, a minimum number of ten-minute average values of windspeed and power are required and averaged. This method takes account of the variations in windspeed between the anemometer and all parts of the wind turbine rotor. In addition, the measurements will be carried out in flat terrain with a dedicated upwind anemometer and with the data accumulated over a test period duration of weeks.

6 Response to Impact Assessment.

BWEA welcomes Ofgem's first impact assessment (IA) for a set of Grid Code changes.

In particular the BWEA notes that Ofgem is supportive of removing mandatory requirements on generators and replacing these with cost reflective market based arrangements[8]

BWEA is raising two major concerns with regard to the document and has some additional comments.

6.1 Impact of proposals on CO_2 emissions

Ofgem have considered the potential impact of windfarms not meeting fault ride through requirements on CO_2 emissions. Ofgem reasonably refer to a report which estimates the additional CO_2 emissions caused by wind turbines not meeting FRT requirements for the worst case scenario of between 0.5 and 4.5MtCO_2 per annum for 10 GW of installed wind[9]. The IA has failed to consider the impact of delays to windfarm projects as a result of the imposition of requirements earlier than is necessary. The scenarios that should have been considered include:

- Delays to projects due to limited availability of turbines that meet all the requirements.
- Delays to projects in the financing and due diligence stage due to obtaining sufficient guarantees and test data from turbine manufacturers and due to negotiations with licensees to achieve approval of all requirements.
- More marginal projects, particularly large offshore projects, delayed by additional project risk until equipment prices fall, power prices rise or perceived risks are reduced.
- Delays associated with Transmission Licensees providing relevant transmission system protection settings for the developer to design the windfarm to meet the site-specific requirements.
- Projects additionally delayed by up to a year due to delays resulting in a missed weather window or an annual planning condition (e.g. avoiding nesting or breeding season for certain birds) for construction.
- Delays due to projects seeking derogations from one of the requirements.

Any delay at this stage of wind development in GB is unlikely to be caught up due to the limited current capacity within the industry and the rapid growth of the market.

BWEA notes the lack of expected progress for wind energy under both NFFO and the RO as shown in the tables in Section 3.1.

The BWEA has considered two scenarios to assess the potential impact of delays on both CO_2 emissions and costs to the consumer.

[8] Ofgem consultation sections 5.8 to 5.10.
[9] Section 6.37 of Ofgem's consultation

6.1.1 Scenario 1

In Scenario 1 wind energy is developed with grid code requirements that do not impede that development and as a result it is assumed that 1000MW is built every year from 2005. It has been assumed that turbines built in the first 2 years do not have full fault ride through capability and therefore additional CO_2 emissions result from spinning reserve.

Year	2005	2006	2007	2008	2009	2010	Total
MW Built	1000	1000	1000	1000	1000	1000	6000
MW cumulative	1000	2000	3000	4000	5000	6000	N/a
Mt CO2 saved by wind	-1.8	-3.7	-5.5	-7.4	-9.2	-11.0	-38.6
Additional Mt CO2 Max	0.5	0.9	0.9	0.9	0.9	0.9	5.0
Additional Mt CO2 Min	0.1	0.1	0.1	0.1	0.1	0.1	0.6

Figure 6.1 Scenario 1 Capacity and CO_2 impacts

The CO_2 savings assumed are 0.6Mt/TWh[10] of wind energy generated and the capacity factor of wind power to be 35%. The additional CO_2 generated by spinning reserve is assumed at between 0.05 and 0.45 Mt/GW wind energy capacity per annum.[11]

Therefore over the years 2005 to 2010 the CO_2 emissions saved in Scenario 1 are between 33.6Mt and 38.0Mt.

[10] Source European Wind Energy Association.

[11] Calculated from Centre for Distributed Generation and Sustainable Electrical Energy, (2004) "Value of fault ride through capability of wind generation in the UK" quoted in Section 6.37 of Ofgem Consultation Document

6.1.2 Scenario 2

In Scenario 2 wind energy development is slightly delayed due to a number of Grid Code requirements being imposed simultaneously. As a result it is assumed that only 500MW is built in 2005 and 1000MW each year after, but that there are no additional CO_2 emissions from spinning reserve.

Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
MW Built	500	1000	1000	1000	1000	1000	5500
MW cumulative	500	1500	2500	3500	4500	5500	N/a
Mt CO2 saved by wind	0.9	2.8	4.6	6.4	8.3	10.1	33.1
Additional Mt CO2 Max	0	0	0	0	0	0	0
Additional Mt CO2 Min	0	0	0	0	0	0	0

Figure 6.2 Scenario 2 Capacity and CO_2 impacts

The CO_2 savings assumed are 0.6Mt/TWh[12] of wind energy generated and the capacity factor of wind to be 35%.

Therefore over the years 2005 to 2010 the CO_2 emissions saved in Scenario 2 are 33.1Mt.

6.1.3 Impact on CO_2 emissions

In Scenario 1 BWEA assumes an unconstrained rate of wind development with associated emissions from additional spinning reserve and in Scenario 2 that wind development is delayed by meeting all grid code requirements but with no additional spinning reserve required. The CO_2 emissions savings are highest in Scenario 1 by between 0.6Mt and 5.0Mt.

Because the IA has not considered a potential delay to wind energy development as a result of a rapid simultaneous implementation of many grid code conditions the impression given is that the only potential outcome of not implementing the grid code conditions is an increase in CO_2 emissions. The BWEA's analysis shows that CO_2 emissions will be lower for a slower implementation of grid code conditions.

[12] Source European Wind Energy Association.

6.2 Impact on cost to consumer

Ofgem has presented figures indicating an addition in cost of between £14million and £155million due to additional spinning reserve if wind energy does not meet fault ride through requirements[13].

In BWEA's Scenario 1 (Section 6.1.1) the wind energy generated to 2010 is 64.4TWh and is 55.2 TWh in Scenario 2 (Section 6.1.2). BWEA has assumed a cost to the consumer of £33/MWh, due to the buyout price, for every unit of wind energy not generated. The difference in the value of lost wind energy between Scenarios 1 and 2 is therefore £304million between 2005 and 2010.

The additional spinning reserve costs are zero in Scenario 2 as Grid Code requirements are met. In Scenario 1 the additional costs are calculated as a maximum of £15.5million per GW per annum and a minimum of £1.4million per GW per annum[14].

In Scenario 1, BWEA assumes an unconstrained rate of wind development with associated costs from additional spinning reserve and in Scenario 2 that wind development is delayed by meeting all grid code requirements but with no additional spinning reserve required. The cost to the consumer is lowest in Scenario 1 by between £303million and £133million.

Because the IA has not considered a potential delay to wind energy development (caused by a rapid simultaneous implementation of many grid code conditions) the impression is that the only potential outcome of not implementing the grid code conditions is an increase in the cost to the consumer. The BWEA's analysis shows that costs to the consumer will be lower for a slower implementation of grid code conditions.

6.3 Additional Comments

- In Section 2.15 specific reference should be made to BWEA's written input and responses to the Grid Code forum.
- Section 5 Options. Ofgem should also consider a fourth option that allows some minor modifications to its proposals where appropriate.
- Section 5.4. No evidence has been offered to show how the future capacities of the networks would be prejudiced by wind having different connection conditions. BWEA is concerned that there is a number of unsubstantiated items in the consultation, which are prejudicial against wind energy. As a concrete example we have examined a statement from SKM on reactive compensation equipment in Section 7.
- Section 6.13 implies that licensees can change the connection requirements out side the normal consultation process by serving notice in advance on users. We believe this is an unacceptable precedent and is outside the remit of Licensees. Ofgem cannot support such actions.
- Section 6.14 refers to there being a "further subsidy by the relaxation of the connection requirements". Ofgem should balance this statement by referring to the historic and hidden subsidies to nuclear generation, and to the costs of externalities (nuclear waste disposal and CO_2 emissions for fossil fuels).

[13] Ofgem consultation Section 6.37.
[14] Calculated from Ofgem consultation 6.37.

- Section 6.18 states the benefit of clarity of requirements. This must be tempered by the cost and risk to the business viability of setting requirements, which delay sales and put manufacturing companies out of business due to cash flow and short-term issues. Recently a new UK manufacturer has pull out of wind turbine manufacturing (FKI).
- In section 6.20 Ofgem have reproduced the data taken from manufacturers on their ability to meet proposed grid code requirements. However were the requirements shown to manufacturers the same as the ones now proposed?
- Section 6.35. What evidence is there to support the view that developers of windfarms have considered the Grid Code proposals before making connection applications?
- Section 6.37 considers the cost and CO_2 emissions of wind not meeting the FRT requirements. Additional data is required to balance this statement. What are the CO_2 emissions costs of delaying windfarms e.g. a delay of 500MW for 1 year to meet new grid code requirements? In addition what is the cost of carrying 1320MW of reserve at present and why should conventional generation have this subsidy?

7 Response to SKM report.

BWEA welcomes the deployment of additional resources to deal with this issue, which has such important ramification for the UK's targets on CO_2 emissions. In particular we welcome the following aspects of the SKM report.

- The tabular assessment of comments.
- The support for drafting changes and clarity of drafting.
- The recognition (Section 4.2) that under super grid fault conditions the voltages seen by embedded generation could be lower than those seen on the supergrid.

BWEA has one major concern with regard to the document as well as some additional comments.

7.1 Reactive compensation reinforcements

SKM state in their report that "the increasing use of non synchronous generating units that are not able to produce the same reactive power requirements as synchronous generating units is causing an increasing amount of reactive compensation devices to be required in the zones where the non synchronous generating units are connected [15]".

BWEA have reviewed the seven-year statements for both Scottish and Southern Energy and Scottish Power between the years 2000 and 2004. From these statements neither transmission network operator has stated plans for installing any reactive power compensation equipment. Nor has either stated that current or future wind farm developments will require reactive power compensation equipment to be installed on their respective networks.

BWEA have also reviewed the National Grid 2004 seven-year statement and National Grid have stated plans to install reactive compensation equipment on to their network over the next 7 years. However, as can be seen in Figure7.1.1, none of this equipment is being located near to approved future wind farm developments. This would therefore suggest that National Grid do not currently expect to provide reactive power compensation due to wind farm development.

[15] Section 2.5 of the SKM report.

Site Name	Node	Unit No	MVAr Gen'n	MVAr Absor'n	Compensation Type	Conn'n Voltage	Com'n Year
BRAMFORD	BRFO40	1	150	75	SVC	400kV	2007
BRAMFORD	BRFO40	4	225		MSC	400kV	2007
CHESTER-FIELD	CHTE11	2	45		MSC	132kV	2008
CHESTER-FIELD	CHTE11	1	45		MSC	132kV	2008
CHESTER-FIELD	CHTE12	4	45		MSC	132kV	2008
CHESTER-FIELD	CHTE12	3	45		MSC	132kV	2008
FLEET	FLEE11	2	52		MSC	132kV	2005
FLEET	FLEE11	1	52		MSC	132kV	2005
FLEET	FLEE11	3			MSC	132kV	2005
FLEET	FLEE12	2	52		Shunt Reactor	132kV	2005
LANDULPH	LAND10	1	60		Relocatable SVC	Tertiary Con'd	2005

Figure 7.1.1 NGC Planned Reactive Compensation[16]

In summary, the data derived from the formal processes for notifying developments to the transmission networks in GB does not support the SKM statement.

The result is a misleading impression that windfarms are imposing costs on the consumer, an impression that has no substance and discriminates against particular market players.

7.2 Additional Comments

- Section 2.5 states that reactive power cannot be moved over long distances and therefore is only useful to deal with local voltage control issues. When the windfarms are not generating the voltage control issues have to be dealt with by other plant. BWEA is surprised therefore that SKM did not conclude that a tapered reactive capability for windfarms operating between 50% and 0% of active power output was appropriate.
- Section 4.2 discusses CC.6.3.15. It may be the case that twelve licence exempt generators have signed Licence Exempt Embedded Generator Agreement's (LEGA), which include Fault Ride Through (FRT) requirements whereas two have not. BWEA understand that only two of these projects are actually connected. Also that the "FRT requirements" which have been agreed are not the same as those in the current proposals.

[16] Extracted from rows of Table B.5 from the National Grid 2004 Seven Year Statement

- We do not agree with SKM's views with regard to the number of turbines connected (Section 4.2 Clause CC6.3.15 (c)(i)). BWEA believes that the requirements should be limited as proposed above.
- SKM state that the reason for implementing different thresholds for the requirements in Scotland to England and Wales is due to "the advanced state of wind farm projects in Scotland"[17]. This is an arbitrary statement and implies that threshold in other parts of the GB system will be changed as wind farm developments advance. If SKM's position is to be considered, they first must provide a clear statement of the basis of this conclusion and how it will be applied in future to other parts of the network.

[17] SKM report Page 28

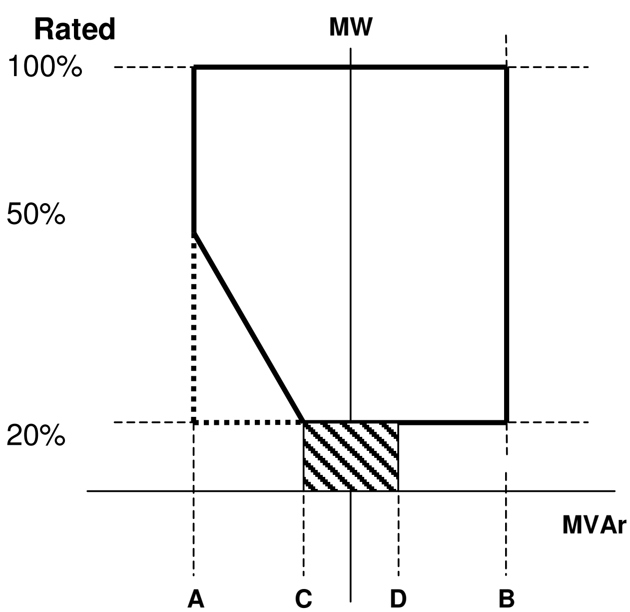
8 Appendix 1: Amended GB Grid Code Clauses

1.1 CC6.3.2 (c&d)

CC.6.3.2

BWEA expects to see the same definitions applied to Scotland as England and Wales.

(c) Subject to the provisions of CC.6.3.2 (d) below, all **Non-Synchronous Generating Units, DC Converters** (excluding current source technology) and **Power Park Modules** (excluding those connected to the **Total System** by a current source **DC Converter**) with a **Completion Date** on or after 1 January 2006 must be capable of supplying **Rated MW** output at any point between the limits 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Grid Entry Point** ~~in England and Wales or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for **Generators** directly connected to the **GB Transmission System** in Scotland~~ [GN1](or **User System Entry Point** if **Embedded**). With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** will apply at all **Active Power** output levels above 20% of the **Rated MW** output as defined in Figure 1. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service.



Point A is equivalent (in MVAr) to: 0.95 leading **Power Factor** at **Rated MW** output
Point B is equivalent (in MVAr) to: 0.95 lagging **Power Factor** at **Rated MW** output
Point C is equivalent (in MVAr) to: -5% of **Rated MW** output
Point D is equivalent (in MVAr) to: +5% of **Rated MW** output

Figure 1 (revised)

Section (d) is deleted because it only applies to projects completed before 1st Jan 2006 in Scotland. See Section 4.1.

~~(d)~~ ~~All **Non-Synchronous Generating Units** and **Power Park Modules** in Scotland with a **Completion Date** after [Grid Code change implementation date] and before 1 January 2006 must be capable of supplying **Rated MW** at the range of power factors either:-~~

~~(i)~~ ~~from 0.95 lead to 0.95 lag as illustrated in Figure 1 at the **User System Entry Point** for **Embedded Generators** or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for **Generators** directly connected to the **GB Transmission System.** With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** will apply at all **Active Power** output levels above 20% of the **Rated MW** output as defined in Figure 1. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service.~~

~~or,~~

~~(ii)~~ ~~from 0.95 lead to 0.90 lag at the **Non-Synchronous Generating Unit** (including **Power Park Unit**) terminals. For the avoidance of doubt **Generators** complying with this option (ii) are not required to comply with CC.6.3.2(b).~~

This clause is reinserted from NGC H/04 consultation June 2004 to cover the shaded area of figure 1.

(d) In the shaded area of Figure 1 the operation is at the discretion of the **Generator** or **DC Converter Station** owner.

1.2 CC 6.3.6

CC.6.3.6

(a) Each **Power Station** with a **Registered Capacity** in excess of 50MW as defined below:

(i) Synchronous **Generating Unit**; or,

(ii) **DC Converter** with a **Completion Date** on or after [change implementation date]; or,

(iii) **Power Park Module** with a **Completion Date** after 1st April 2007~~in operation in England and Wales on or after 1 January 2006 (irrespective of its **Completion Date**); or~~,

~~(iv)~~ ~~**Power Park Module** in operation in Scotland on or after 1 January 2006 (with a **Completion Date** after 1 July 2004 and in a **Power Station** with a **Registered Capacity** of 30MW or above),~~

must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **GB Transmission System** or the **User System** in which it is **Embedded**.

(b) Each Power Station with a **Registered Capacity** in excess of 50MW in England and Wales and in excess of 5 MW in Scotland as defined below:

(i) Synchronous **Generating Unit**; or,

(ii) **DC Converter** (with a **Completion Date** on or after [change implementation date] excluding current source technologies); or

(iii) **Power Park Module** with a **Completion Date** after 1st April 2006in England and ~~Wales with a **Completion Date** on or after 1 January 2006; or,~~

~~(iv) **Power Park Module** in Scotland irrespective of **Completion Date**,~~

must be capable of contributing to voltage control by continuous changes to the **Reactive Power** supplied to the **GB Transmission System** or the **User System** in which it is **Embedded**.

1.3 CC 6.3.7

CC.6.3.7

(a) Each **Generating Unit,** and **DC Converter** or **Power Park Module** with a **Completion Date** after 1st April 2007 and a **Registered Capacity** of more than 100MW ~~(excluding **Power Park Modules** in Scotland with a **Completion Date** before 1 July 2004 or in a **Power Station** in Scotland with a **Registered Capacity** less than 30MW)~~ must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (**BC3**). The **Frequency** control device (or speed governor must be designed and operated to the appropriate:

(i) **European Specification**; or

(ii) in the absence of a relevant **European Specification**, such other standard which is in common use within the European Community; as at the time when the installation of which it forms part was designed or (in the case of modification or alteration to the **Frequency** control device (or turbine speed governor)) when the modification or alteration was designed. The **European Specification** or other standard utilised in accordance with sub-paragraph CC.6.3.7 (a) (ii) will be notified to **NGC** as:

(i) part of the application for a **Bilateral Agreement;** or

(ii) part of the application for a varied **Bilateral Agreement;** or

(iii) soon as possible prior to any modification or alteration to the **Frequency** control device (or governor); and

(b) The **Frequency** control device (or speed governor) in co-ordination with other control devices must control the **Generating Unit, DC Converter** or **Power Park Module Active Power Output** with stability over the entire operating range of the **Generating Unit, DC Converter** or **Power Park Module**; and

(c) The **Frequency** control device (or speed governor) must meet the following minimum requirements:

Windfarms cannot guarantee islanded operation refer to Section 4.9

(i) Where a **Generating Unit**~~,~~ or **DC Converter** ~~or **Power Park 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 **Generating Unit, DC Converter** or **Power Park 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 **Generating Unit, DC Converter** or **Power Park Module** is only required to operate within the **System Frequency** range 47 - 52 Hz as defined in

(ii) the **Frequency** control device (or speed governor) must be capable of being set so that it operates with an overall speed **Droop** of between 3% and 5%;

(iii) in the case of all **Generating Units, DC Converters** or **Power Park Modules** other than the **Steam Unit** within a **CCGT Module** the **Frequency** control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the speed governor) deadband should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**; For the avoidance of doubt, the minimum requirements in (ii) and (iii) for the provision of **System Ancillary Services** do not restrict the negotiation of **Commercial Ancillary Services** between **NGC** and the **User** using other parameters; and

(d) A facility to modify, so as to fulfill the requirements of the **Balancing Codes**, the **Target Frequency** setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 _0.1 Hz should be provided in the unit load controller or equivalent device.

(e)

(i) Each Synchronous **Generating Unit** and/or **CCGT Module** which has a **Completion Date** after 1 January 2001 in England and Wales, and after 1 April 2005 in Scotland, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(ii) Each **DC Converter** at a **DC Converter Station, which has a Completion Date on or after [change implementation date],** must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3**.**

(iii) Each **Power Park Module** with a **Completion Date** ~~in operation in England and Wales on or~~ after ~~1 January 2006~~ 1st April 2007 and a **Registered Capacity** of more than 100MW ~~(irrespective of its **Completion Date**)~~ must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

~~(iv) Each **Power Park Module** in operation on or after 1 January 2006 in Scotland (with a **Completion Date** on or after 1 April 2005 and a **Registered Capacity** of 30MW or greater) must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.~~

(f) For the avoidance of doubt, the requirements of Appendix 3 do not apply to:-

(i) Synchronous **Generating Units** and/or **CCGT Modules** which have a **Completion Date** before 1 January 2001 in England and Wales, and before 1 April 2005 in Scotland, for whom the remaining requirements of this clause CC.6.3.7 shall continue to apply unchanged: or

(ii) **DC Converters** at a **DC Converter Station** which have a **Completion Date** before [change implementation date]; or

(iii) **Power Park Modules** ~~in operation before 1 January 2006~~ with **Completion Dates** before 1 April 2007 and a **Registered Capacity** of less than 100MW for whom only the requirements of **Limited Frequency Sensitive Mode** (BC.3.5.2) operation shall apply; or

~~(iv) **Power Park Modules** in operation after 1 January 2006 in Scotland which have a **Completion Date** before 1 April 2005 for whom the remain~~ing requirements of this clause ~~CC.6.3.7 shall continue to apply unchanged.~~

1.4 CC 6.3.15

CC.6.3.15 Fault Ride Through

Clause 6.3.15 only applies to **Power Stations** with a **Registered Capacity** of greater than 50MW

(a) Short circuit faults at **Supergrid Voltage** up to 140ms in duration

(i) Each **Generating Unit**, **DC Converter**, or **Power Park Module** with a **Completion Date** later than 1st April 2006 and any constituent element thereof shall remain transiently stable and connected to the **System** without tripping of any **Generating Unit, DC Converter** or **Power Park Module** and / or any constituent element, for a close-up solid three-phase short circuit fault or any unbalanced short circuit fault on the **GB Transmission System** operating at **Supergrid Voltages** for a total fault clearance time of up to 140 ms. A solid three-phase or unbalanced earthed fault results in zero voltage on the faulted phase(s) at the point of fault. The duration of zero voltage is dependent on local protection and circuit breaker operating times. This duration and the fault clearance times will be specified in the **Bilateral Agreement**. Following fault clearance, recovery of the **Supergrid Voltage** to 90% may take longer than 140ms as illustrated in Appendix 4 Figures CC.A.4.1 (a) and (b).

Change of completion date: see sections 4.2 and 4.10. Based on Ofgem's option 3 Paragraph CC.6.3.15 (a)(ii)

(ii) Each **Generating Unit** or **Power Park Module** with a **Completion Date** later than 1st April 2006 shall be designed such that upon both clearance of the fault on the

GB Transmission System as detailed in CC.6.3.15 (a) (i) and ~~within 0.5 seconds of the~~ restoration of the **Supergrid Voltage** to the minimum levels specified in CC.6.1.4, **Active Power** output shall be restored at a rate of at least 10% of **Rated MW** per second to at least 90% of the level available immediately before the fault. During the period of the fault as detailed in CC.6.3.15 (a) (i) each **Generating Unit** or **Power Park Module** shall generate maximum reactive current without exceeding the transient rating limit of the **Generating Unit** or **Power Park Module** and / or any constituent element.

(iii) Each **Generating Unit** or **Power Park Module** with a **Completion Date** later than 1st April 2007 shall be designed such that upon both clearance of the fault on the **GB Transmission System** as detailed in CC.6.3.15 (a) (i) and within 0.5 seconds of the restoration of the **Supergrid Voltage** to the minimum levels specified in CC.6.1.4, **Active Power** output shall be restored to at least 90% of the level available immediately before the fault. During the period of the fault as detailed in CC.6.3.15 (a) (i) each **Generating Unit** or **Power Park Module** shall generate maximum reactive current without exceeding the transient rating limit of the **Generating Unit** or **Power Park Module** and / or any constituent element.

Change from iii to iv

(i~~ii~~v) Each DC Converter shall be designed to meet the Active Power recovery characteristics as specified in the Bilateral Agreement upon clearance of the fault on the GB Transmission System as detailed in CC.6.3.15 (a) (i).

(b) **Supergrid Voltage** dips greater than 140ms in duration

In addition to the requirements of CC.6.3.15 (a) each **Generating Unit** or **Power Park Module** and / or any constituent element, each with a **Completion Date** on or after the ~~[**Grid Code** change implementation date]~~ 1st April 2006 shall:

(i) remain transiently stable and connected to the **System** without tripping of any **Generating Unit** or **Power Park Module** and / or any constituent element, for balanced **Supergrid Voltage** dips and associated durations anywhere on or above the heavy black line shown in Figure 5. Appendix 4 and Figures CC.A.4.3 (a), (b) and (c) provide an explanation and illustrations of Figure 5; and,

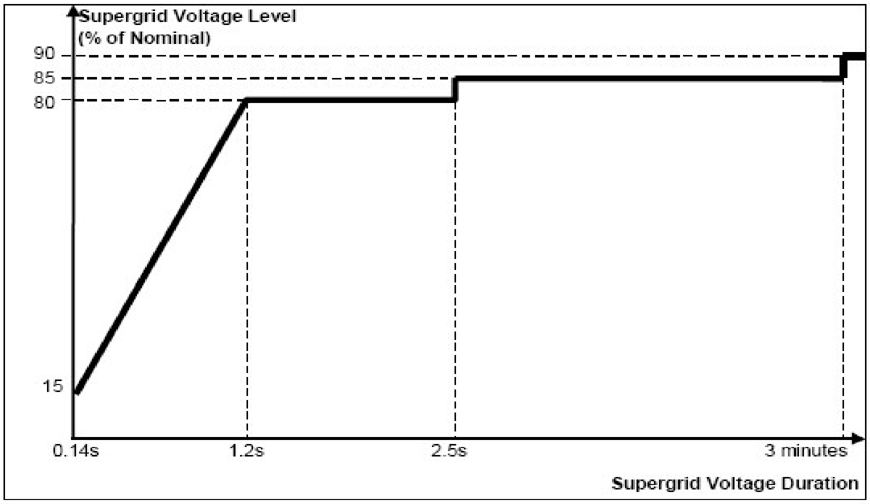


Figure 5

Option 4 Paragraph CC.6.3.15(b)(ii) and (iii)

To include 132kV transmission system connections in Scotland see Section 4.4.

(ii) provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced voltage at its **Grid Entry Point** ~~**Supergrid Voltage**~~ [GN2](or the retained balanced voltage at the **User System Entry Point** if **Embedded**) and shall generate maximum reactive current without exceeding the transient rating limits of the **Generating Unit** or **Power Park Module** and any constituent element; and,

BWEA has accepts Ofgem's Option 4 and has implemented EoN requirements immediately and more rapid active power restoration a year later see Sections 4.2 and 4.10.

(iii) restore **Active Power** output, at a minimum rate of 10% of Rated MW per second, following **Supergrid Voltage** dips as described in Figure 5, following~~within 1 second of~~ restoration of the voltage at the **Grid Entry Point** ~~**Supergrid Voltage**~~**d** to the minimum levels specified in CC.6.1.4 (or ~~within 1 second of~~ following restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), to at least 90% of the level available immediately before the occurrence of the dip except in the case of a **Non-Synchronous Generating Unit** or **Power Park Module** where there has been a reduction in the **Intermittent Power Source** in the time range in Figure 5 that restricts the **Active Power** output below this level.

In addition to the requirements of CC.6.3.15 (b) each **Generating Unit** or **Power Park Module** and / or any constituent element, each with a **Completion Date** on or after the 1st April 2007 shall:

(iv~~ii~~) restore **Active Power** output, following **Supergrid Voltage** dips as described in Figure 5, within 1 second of restoration of the voltage at the **Grid Entry Point** ~~**Supergrid Voltage**~~ to the minimum levels specified in CC.6.1.4 (or within 1 second of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), to at least 90% of the level available immediately before the occurrence of the dip except in the case of a **Non-Synchronous Generating Unit** or **Power Park Module** where there has been a reduction in the **Intermittent Power Source** in the time range in Figure 5 that restricts the **Active Power** output below this level.

For the avoidance of doubt a balanced **Supergrid Voltage** meets the requirements of CC.6.1.5 (b) and CC.6.1.6.

(c) Other Requirements

Reject Option 2 in Ofgem's consultation, see Section 4.3, therefore retain (i) below

(i) In the case of a **Power Park Module** (comprising of wind-turbine generator units), the requirements in CC.6.3.15(a) and CC.6.3.15(b) do not apply when the **Power Park Module** is operating at less than 5% of its **Rated MW** or during very high wind speed conditions when more than 50% of the wind turbine generator units in a **Power Park Module** have been shut down or disconnected under an emergency shutdown sequence to protect **User's Plant** and **Apparatus**

This clause (ii) is made superfluous by the specific fault ride through specifications in (a) and (b) see Section 4.5~~[GN3]~~

~~*(ii)* In addition to meeting the conditions specified in CC.6.1.5(b) and CC.6.1.6, each **Non-Synchronous Generating Unit** or **Power Park Module** and any constituent element thereof will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by **System Back-Up Protection** on the **GB Transmission System** operating at **Supergrid Voltage**.~~

Clause c iii deleted as all retrospective – refer to Section 3.1

~~*(iii)* In the case of a **Power Park Module** in Scotland with a **Completion Date** before 1 January 2004 and a **Registered Capacity** less than 30MW the requirements in CC.6.3.15 (a) do not apply. In the case of a **Power Park Module** in Scotland with a **Completion Date** on or after 1 January 2004 and before 1 July 2005 and a **Registered Capacity** less than 30MW the requirements in CC.6.3.15 (a) are relaxed from the minimum **Supergrid Voltage** of zero to a minimum **Supergrid Voltage** of 15% of nominal. In the case of a **Power Park Module** in Scotland with a **Completion Date** before 1 January 2004 and a **Registered Capacity** of 30MW and above the requirements in CC.6.3.15 (a) are relaxed from the minimum **Supergrid Voltage** of zero to a minimum **Supergrid Voltage** of 15% of nominal. In the case of a **Power Park Module** in Scotland with a **Completion Date** before 1 January 2005 the requirements in CC.6.3.15 (b) do not apply.~~

1.5 CONNECTION CONDITIONS - APPENDIX 3

MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE AND OPERATING RANGE for ~~new~~ Synchronous Generating Units and/or CCGT Modules with a Completion Date after 1 January 2001 in England and Wales and 1 April 2005 in Scotland, and DC Converter Stations with a Completion Date on or after [change implementation date] and Power Park Modules ~~in~~ ~~operation (irrespective of their Completion Date) on or~~ with a **Completion Date** after ~~1 January 2006~~1st April 2007

CC.A.3.1 SCOPE

The **Frequency** response capability is defined in terms of **Primary Response**, **Secondary Response** and **High Frequency Response**. This appendix defines the minimum **Frequency** response requirement profile for:-

(a) each Synchronous **Generating Unit** and/or **CCGT Module** which has a **Completion Date** after 1 January 2001 in England and Wales and 1 April 2005 in Scotland. and/or

(b) each **DC Converter** at a **DC Converter Station** which has a **Completion Date** on or after [change implementation date] and/or

(c) each **Power Park Module** with a **Completion Date** after 1st April 2007 ~~in operation in England and Wales on or after 1 January 2006 (irrespective of the **Completion Date** of the **Power Park Module**).~~

~~(d) each **Power Park Module** in operation in Scotland on or after 1 January 2006~~ (with a ~~**Completion Date** after 1 April 2005 and in **Power Stations** with a **Registered Capacity** of 30MW or above).~~

For the avoidance of doubt, this appendix does not apply to:-

(i) Synchronous **Generating Units** and/or **CCGT Modules** which have a **Completion Date** before 1 January 2001 and/or

(ii) **DC Converters** at a **DC Converter Station** which have a **Completion Date** before [change implementation date] and/or

(iii) **Power Park Modules** with a **Completion Date** ~~in operation (irrespective of their **Completion Date**)~~ before 1st April 2007 ~~1 January 2006~~ or individually to **Power Park Units** or

~~(iv) **Power Park Modules** in operation in Scotland with a **Completion Date** befor~~e 1 ~~April 2005 and **Power Park Modules** in Scotland in **Power Stations** with a **Registered Capacity** less than 30MW or~~

~~(v) To **Small Power Stations**.~~

(iv) To **Power Stations** with a **Registered Capacity** of less than 50MW

1.6 BC1.A.1.8.3

Wording clarified for wind power see section

BC1.A.1.8.3 **NGC** will assume~~rely on~~ the **Power Park Units** specified in such **Power Park Module Availability Matrix** will be running subject to sufficient wind resource being available ~~as indicated in the **Power Park Module Availability Matrix**~~ when it issues an instruction in respect of the **Power Park Module**;

Centre for Distributed Generation and Sustainable Electrical Energy

Response on OFGEM Grid Code Consultation

Prof Nick Jenkins

February 2005

MANCHESTER 1824
The University of Manchester

UNIVERSITY OF STRATHCLYDE

Response on OFGEM Grid Code Consultation

1) The response was based on the following documents: SKM Report New Generation Technologies and GB Grid Codes, OFGEM Grid Consultation SA/2004, OFGEM Grid Consultation H/04, National Grid GB Text Extracts of Grid Codes for OFGEM Consultation.

2) Researchers of the Centre have been active for some years in the investigation of the effect of non-synchronous wind generation on large power systems. The expertise of the Centre is on the more general aspects of this issue and is not based on a detailed knowledge of the rather involved process that has accompanied the development of the current Grid Code proposals.

3) However from our research work, the Centre strongly agrees that Option 3 (Page 18 of H/04, i.e. the do nothing option) is not appropriate and it is essential to take steps to integrate new forms of generation into the GB power system.

4) In order to make progress on this matter the Centre would tend to support Option 2 (Accept the proposals with the Supplementary Changes)

5) In accordance with the mission of the Centre to provide underpinning research for the Government Renewable Energy Targets, I would like to make several technical comments:
    a. All our work indicates that ensuring non-synchronous generation has appropriate fault ride through capability is important. We were pleased to note that the report from the Centre "Value of fault ride through capability of wind generation in the UK" had been quoted by OFGEM in their IA. Our technical simulations, particularly of Fixed Speed Induction Generators, reinforce this general conclusion. Provided the data of Figures 1 and 2 on Pages 27 and 28 of H/04 is robust, then it is desirable that the generators provide the required level of performance as required in the proposals.

    b. Our understanding of the most recent proposals (Issue 3, revision 5, 4 Feb 2005) is that is does not include any reference to system damping or an explicit requirement for a PSS function. An earlier version of the Scottish Proposals SB/2002 included the statement "The displacement of conventional plant with PSS capability will inevitably reduce the small-signal instability (system damping). This in turn will reduce boundary transfer capability and will either require constraining-on of conventional plant with PSS or lead to a lower overall acceptable level of wind generation". We believe this statement is still relevant and our recent work has made clear to us the importance of the control systems of non-synchronous plant and the potential opportunities of them making significant contributions to system stability. Thus, our advice would be that further consideration is given to the capability required from non-conventional generation to provide advanced control functions that benefit the system.

c. We also understand that there is a requirement to provide validated models of the plant. The models are to be validated by test. We would only remark that we have found it very difficult to obtain test data with which to validate our models and would like to emphasise the importance of this activity.

d. We were surprised by the lack of discussion on the Negative Phase Sequence requirement and the statement in Table 1 that all manufactures could meet this requirement. Clause CC.6.3.8 requires that the generation will withstand a close up phase-phase fault for the clearance time of back-up protection. From our modelling, we believe this to be a demanding condition and look forward to seeing test results that confirm this capability.

6) We are disappointing to note that the detailed technical requirements proposed differ from those in other national Grid Codes. Although these may be similar (as discussed in the IA) such technical differences do not assist the manufacturers.

7) In conclusion we strongly support this initiative and re-conform that Option 3 is not appropriate. However we would also like to draw to your attention that, in our view, the present proposals although important and the subject of very considerable work, are unlikely to be the last word on the matter. Higher penetrations of non-synchronous generation are likely to impose further requirements particularly on the control systems of both non-synchronous and synchronous plant.

DTI ref CCCC/101/00034A
Your ref HA/2004 &SA/2004
Date 25 February 2005

Mr Gareth Evans
Technical Directorate
Ofgem
9 Millbank
London
SW1P 3GE

Dear Gareth,

Grid Code Consultation H/2004 &SA/2004- GB Grid Code Connection Conditions for Wind Generation

Thank you for the opportunity of commenting on the above proposals.

As discussed at our meeting on the 10 February 2004, the provisions for wind generation connection now reflect a set of broad system performance criteria at the connection boundary. This allows technical flexibility for generators in the detailed engineering aspects of any development to meet these criteria.

The main concern from the Engineering Inspectorate is the apparent lack of provisions to control system modes of oscillation. These are normally controlled in conventional generating plant by power system stabilizers (PSS).

Power system oscillations, which raise stability concerns, occur with conventional plant in the low frequency range typically between 0.2 and 2.5Hz. These are caused by the rotors of machines behaving as rigid bodies, oscillating with respect to one another using the electrical transmission path between them to exchange energy. There are many different modes in which such oscillations may occur, often simultaneously.

Experience suggests that it is not unusual for a generating unit to participate in both local and inter-area modes of oscillation. Given the introduction of new prime mover arrangements with wind generation (i.e. gearbox vibration) and different frequencies of mechanical oscillation, due to different forcing functions (i.e. such as wind gusting, blade traversing etc.) it would seem appropriate that this area is examined to see

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whether there will be a requirement to fit power system stabilizers on new equipment.

With the introduction of gas fired combined cycle gas turbines in the 1990's there was a requirement to examine the PSS settings given the new prime mover characteristics. It also became a rigidly enforced connection requirement that PSS was procured, installed and tuned as part of meeting the contractual connection and Grid Code conditions.

It appears that with the introduction of wind generation we could be in an analogous situation (be it with different frequency range issues), and this should be examined technically to ensure that new and existing PSS equipment is adequate for the reduction of local and inter-area system oscillations.

Please contact me if you wish to discuss any aspects of this letter.

Yours sincerely

David Gray

Senior Engineering Inspector

ENERCON

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date: 11 March 2005

copy: Antony Johnson, National Grid Transco
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David Payne, National Grid Company
Simon Vince, ENERCON
Stephan Wachtel, ENERCON
Matthias Dernbach, ENERCON

Mr. Gareth Evans
OFGEM
9 Millbank
London SW1P 3GE

England

The GB Grid Code drafting that incorporates the H/04 and SA/2004 proposals and the Supplementary Changes proposals

Dear Mr. Evans,

Sorry for the late response to the published documents of the consultation processes H/04 and SA/2004 to change the GB Grid Code.

ENERCON is aware of the efforts made, to achieve new grid code requirements in Great Britain. We agree with the clarifications introduced through the consulation of SKM and would welcome to include the suggested options 2, 3 and 4 concerning the fault-ride-requirements in CC 6.3.15.

In this context ENERCON likes to mention that the requirement to ride through "zero- voltage" on the 400 kV- and 275 kV voltage levels [CC.6.3.15(a)(i)] can lead to stability problems in specific grid situations, because of the decoupling of different parts of the grid.

Additionally the requirement of maximum reactive current infeed during the period of the fault [CC.6.3.15(a)(ii)] could result in over-voltages after the clearance of the fault, depending on the specific grid situation.

ENERCON welcomes the introduction of the requirement to submit validated models and to allow the submission of complete models which contain the information asked for in PC.A.5.4.2.

Please contact Mr. Matthias Dernbach (phone: +49 4941 927 450, matthias.dernbach@enercon.de) if there are questions to this comments.

Best regards,

Stefan Hartge
Head Electrical Engineering
ENERCON GmbH

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Mr Gareth Evans
Ofgem
9 Millbank
London
SW1P 3GE

Monday, 28th February 2005

Dear Gareth,

Grid Code Consultation H/04 and SA/2004 – Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)

Thank you for the opportunity to respond to the above GB Grid Code consultations H/04 and SA/2004. This response is on behalf of E.ON UK plc, E.ON UK CHP Ltd, Citigen (London) Limited and Cottam Development Centre Limited. We have combined our responses to the two consultations, in view of the fact that they will result in changes to one Code.

The Generic Provisions consultation process has been long and detailed. We have participated in the development of these proposals and in the Forum, and have commented extensively on drafts of the Generic Provisions as we have seen them. We are pleased that many of the points we have raised have been addressed by the Transmission Licensees in a constructive way. As an aside, we found the publication of the SKM report to be helpful. The tabular summary of changes proposed and their acceptance or otherwise by the Transmission Licensees was useful.

We welcome the views expressed by the Authority on the potential for removal of mandatory requirements on generators and replacing them with appropriate market arrangements. We agree that this should be possible, and look forward to working with the rest of the industry to achieve this in the longer term.

Implementation Dates

We continue to hold reservations regarding the impact of the proposed changes on existing and planned projects, e.g. projects which have already committed significant development funds, have a signed connection agreement or for which procurement, construction or commissioning may already be in progress. This is due to the fact that many of the proposed new requirements are potentially applicable to all new and existing projects, irrespective of their completion date. Other requirements are applicable only to projects completed after specified dates, several of which significantly pre-date the present date (or the change implementation date).

We are primarily concerned regarding Power Park Modules in Scotland, as many of these are potentially subject to many of the Grid Code requirements by virtue of falling into the Medium or Large Power Station categories (i.e. ≥5MW). We would point out that even License Exempt plant is likely to be subject to the proposed changes because the Grid Code conditions, especially the Connection Conditions, are likely to be applied via bilateral agreements (e.g. LEGAs, BEGAs, BELLAs) for these projects.

We understand that it is intended that the proposed Grid Code changes should not result in significant impacts on either existing plant or committed projects. Hence, the possible effects of the proposed changes on these projects should be properly considered.

We note NGT's argument that wind farm penetration may be more advanced in Scotland than in England and Wales and that they believe this justifies earlier implementation dates for projects in Scotland for some of the requirements. We also note that NGT state that some plant currently commissioning in Scotland does incorporate certain capabilities (e.g. frequency response) and that certain requirements are already included in connection agreements already signed with generators in England and Wales (many of which are not yet commissioned though). Whilst this may be true for some projects, these may represent only a small proportion of the total number of projects which may be affected if the implementation dates are set too early.

Table 1 includes examples of the requirements which may apply retrospectively to existing and committed projects, based on our understanding of the proposed changes. It shows how additional requirements are gradually introduced over time. Any other requirements not included in the table, that are not qualified in the proposed changes with a specified completion date, will apply to all relevant projects, irrespective of their completion date, and will become effective from the change implementation date (unless specified otherwise).

Taking into account that many of the proposed changes are written as potentially being retrospectively applicable, as shown in Table 1, we do not believe that the impacts on existing and committed projects have been thoroughly assessed; for example we are not aware that a survey has been undertaken or published to assess the number of such projects which would be affected by the current proposals, those which would already comply, and the number that would have difficulty in achieving compliance.

Consequently, we remain concerned that many of the proposed Grid Code changes appear to introduce implementation dates considerably before the likely change implementation date, and that these may result in significant impacts on some projects.

We therefore request that Ofgem and the transmission licensees consider the potential for increasing, wherever possible, the retrospective implementation dates from those currently proposed to the change implementation date (assumed to be 1 April 2005). This change would still maintain an earlier introduction of several of the requirements into Scotland than in England and Wales (e.g. frequency control contribution, voltage control contribution, full reactive power capability).

Table 1 **Examples of proposed Grid Code requirements for Power Park Modules, in chronological order of applicable completion date.**

Applicable Completion Date	**Plant Included in Requirement Scope** *(not exhaustive)*	**Clause**	**Requirement**
None (i.e. applies irrespective of completion date)	Power Park Modules with RC ≥ 5MW in Scotland RC ≥ 50MW in England & Wales	CC.6.3.2(b)	Zero transfer of reactive power at Entry Point
	Power Park Modules in Scotland RC ≥ 5MW	CC.6.3.6(b)	Voltage control contribution
	Power Park Modules in E&W RC ≥ 100MW	CC.6.3.7(a)	Frequency control device to meet requirements of BC3
	Power Park Modules in Scotland RC ≥ 30MW	CC.6.3.15(a)	Fault Ride Through (short circuit faults ≤ 140ms) *(relaxed to 15% voltage)*
	Power Park Modules (in all GB) RC ≥ 100MW	BC.3.5.1	Frequency response capability
	Power Park Modules in E&W RC ≥ 100MW	BC.3.5.4(f)	Instructions for Frequency Sensitive Mode

Applicable Completion Date	**Plant Included in Requirement Scope** *(not exhaustive)*	**Clause**	**Requirement**
1 Jan 2004	Power Park Modules in Scotland RC $\geq$ 30MW	CC.6.3.15(a)	Fault Ride Through (short circuit faults $\leq$ 140ms) *(full requirement: 0% voltage)*
1 Jan 2004 to 1 Jul 2005	Power Park Modules in Scotland 5MW $\leq$ RC < 30MW	CC.6.3.15(a)	Fault Ride Through (short circuit faults $\leq$ 140ms) *(relaxed to 15% voltage)*
1 July 2004	Power Park Modules in Scotland RC $\geq$ 30MW	CC.6.3.6(a)	Frequency control contribution *(effective from 1 January 2006)*
		CC.6.3.7(a)	Frequency control device to meet requirements of BC3
	Power Park Modules 30MW $\leq$ RC< 100MW in Scotland	BC.3.5.1	Frequency response capability
	Power Park Modules in Scotland RC $\geq$ 30MW	BC3.5.3(b)	Operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode *(effective from 1 January 2006)*

Applicable Completion Date	**Plant Included in Requirement Scope** *(not exhaustive)*	**Clause**	**Requirement**
	Power Park Modules in Scotland RC $\geq$ 30MW	BC3.5.4(f)	Instructions for Frequency Sensitive Mode
1 April 2005	Power Park Modules in Scotland RC $\geq$ 30MW	CC.6.3.7(e)	Frequency response profile (Appendix 3) *(effective from 1 January 2006)*
Change implementation date	Power Park Modules with RC $\geq$ 5MW in Scotland RC $\geq$ 50MW in England & Wales	CC.6.3.15(b)	Fault Ride Through (voltage dips $>$ 140ms)
	Power Park Modules in Scotland RC $\geq$ 5MW	CC.6.3.2(d)	Full reactive power capability (two options)
1 July 2005	Power Park Modules in Scotland 5MW $\leq$ RC $<$ 30MW	CC.6.3.15(a)	Fault Ride Through (short circuit faults $\leq$ 140ms) *(full requirement: 0% voltage)*
1 Jan 2006	Power Park Modules with RC $\geq$ 5MW in Scotland RC $\geq$ 50MW in England & Wales	CC.6.3.2(c)	Full reactive power capability (specified at Entry Point)
	Power Park Modules in E&W RC $\geq$ 50MW	CC.6.3.6(a)	Frequency control contribution
		CC.6.3.6(b)	Voltage control contribution

Applicable Completion Date	Plant Included in Requirement Scope *(not exhaustive)*	Clause	Requirement
		CC.6.3.7(e)	Frequency response profile (Appendix 3)
	Power Park Modules in E&W RC ≥ 100MW	BC3.5.3(b)	Operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode

This change could be achieved by a new sentence in CC.6.3.1, providing exemption from CC.6.3 for Power Park Modules completed before the change implementation date. Any other exemptions in the individual detailed clauses that are earlier than this date, would then need to be removed. If this proposal fails to capture requirements already agreed for projects completed before the change implementation date, then these requirements could be included in the appropriate site-specific supplemental or bilateral agreements.

We would also make the following detailed comments, primarily regarding implementation dates.

Clause CC.6.3.7(a) should also repeat the restricted scope of BC3 (i.e. only Large Power Stations of 30MW and above are covered).

The last sentence of clause CC.6.3.15(c) (iii) is superfluous as CC.6.3.15(b) does not apply to any plant completed before the change implementation date. In fact, we question whether CC.6.3.15(c) (iii) should not be deleted entirely, in accordance with the above proposal. Any remaining exemptions would then be better included within CC.6.3.15(a).

BC.3.5.1 appears to require frequency response capability from all Power Park Modules of 100MW and above, irrespective of completion date. This appears to be inconsistent with CC.6.3.6(a) and CC.6.3.7(a) which do not introduce any capability requirements for Power Park Modules in Scotland until 1 July 2004.

There appears to be an inconsistency in BC3.5.3(b) which, as written, appears to require frequency response operation from some Power Park Modules in Scotland less than 30MW, whereas this plant is excluded from the Scope of BC3. Hence BC3.5.3(b), second sentence, should read "and in a Power Station with a Registered Capacity of 30MW and greater …." instead of "or in a Power Station with a Registered Capacity of 30MW and greater ….". (Table 1 is written assuming this error is corrected.)

A few grammatical comments which we consider are important to remove ambiguities:

CC.A.3.1 SCOPE

In the lists of included items, (a) to (d), and excluded items, (i) to (v), some items have "and/or" at the end; this is not necessary for items in a list and is confusing; therefore we recommend deleting the "and/or" text.

Also, item (iv) in the list of excluded items actually contains three items, the first two being joined with "or", the final two being joined with "and". We interpret this item as excluding all three named items from Appendix 3; we consider it would improve clarity if these were all listed as separate items, thereby expanding the list to a total of seven items (an alternative, though not in preference, would be to use "nor" instead of "or" and "and").

Fault Ride Through

CC.6.3.15 (b) (ii) We think that this clause should also include a qualification to allow for restrictions of output power due to reduction in the Intermittent Power Source, similar to clause CC.6.3.15 (b) (iii), as the duration of the voltage dip is potentially quite long.

Regarding the new options presented for some of the fault ride through clauses, our comments are as follows:

Option 2 CC.6.3.15 (c) (i)
We do not support this option. We believe that the existing clause,

including the high wind speed relaxation is justified, as set out in the supporting documentation previously produced by the transmission licensees. This relaxation was originally introduced over a year ago and it has not been raised as an item for concern by any party during the various fora and consultation processes. If the fault ride through requirements are to be applied with only a few Power Park Units connected, then we have strong doubts over our ability to achieve compliance in some cases.

Option 3 CC.6.3.15 (a) (ii)
We welcome and support this option which we believe appears to be a reasonable qualification of the requirement, whilst at the same time removing an ambiguity.

Option 4 CC.6.3.15 (b) (iii)
We support this option. The voltage dip in the distribution network may be either higher or lower than that in the supergrid system, depending on the proportion of generation to load, and load and network characteristics etc. However, in all cases, we consider that the voltage at the User System Entry Point to be the most appropriate reference that is physically related to the ability of embedded generators to export active power output.

We support the rest of the Supplemental Drafting.

If you have any queries, please do not hesitate to contact me.

Yours sincerely

Claire Maxim
Lead Contract Manager

From: david.m.ward@magnox.co.uk
Sent: 21 January 2005 12:57
To: Gareth Evans
Subject: Ofgem "Minded to" letters

To Gareth Evans
Ofgem

(By email)

Gareth

Ofgem "Minded to" letters on Grid Code Consultations H/04 and SA/01

Thank you for your email to me notifying me that the two "minded to" letters had been published on the Ofgem website. This email is my response on behalf of British Nuclear Group. (British Nuclear Group is the new name for that part of BNFL which includes Magnox Electric plc). My comments are not confidential.

I generally support Ofgem's 'minded to' position, and the inclusion in the GB Grid Code of the H/04 and SA/01 changes as modified by the supplementary proposals attached to the 'minded to' letters. I also believe the impact assessment is generally correct in its methods and conclusions. However I have a few comments on points of detail which are described below.

In my comments on the wording proposed in H/04, I pointed out that there was a difficulty with the "fault ride through " proposals as they were made retrospective on all existing synchronous generating plant, and I was not convinced that all existing synchronous plant could demonstrate that it was compliant with all the requirements, particularly the extended voltage depression. The latest proposals distinguish between the requirements during a fault up to 140 milliseconds which are applicable retrospectively on all generating plant [CC.6.3.15 (a) (i)] , and the requirements for a prolonged voltage depression, which are only applicable to generating plant with a completion date after the change implementation date [CC.6.3.15 (b) (i)]. The latter requirement has also been relaxed slightly with regard to the duration of 80% voltage. The difficulty arises because the wording has been strengthened to include the words "without tripping .... any constituent element". It is not clear what is meant by a 'constituent element', and how far it is all-embracing. In any large power station there are many auxiliary systems and ancillary systems, and some of these are traditionally supplied via electrically held contactors, which are likely to trip out if the local supply voltage falls momentarily below 75% (see BS 774 Part 2 and BS EN 60947-4-1). In some power stations during normal operations, the auxiliaries are supplied via a unit transformer and unit board fed from the generator terminals, so are protected by the generator against grid voltage depressions. Hence this is probably not an issue for them. However, other power stations supply some of their auxiliaries from a station transformer and station board that is directly gird connected, so the auxiliaries will see the voltage depression. I know of at least one example when a generating unit had to be shut down a few minutes after a grid fault and severe voltage depression because a number of auxiliaries had tripped or locked out.

I would agree that it is desirable for system security for all generating plant to be able to ride through system faults and severe voltage depressions. This is demonstrated by the blackouts which occurred in Italy and the USA recently, which I understand were exacerbated by some power stations tripping off early on low voltage. But perhaps the impact of the fault ride-through requirements on the design of the auxiliary systems in large power stations is greater than has been realised. It is unrealistic to expect existing elderly power stations to make major modifications to their auxiliary systems, but it is reasonable to expect new power stations to be designed to meet the requirements, which I am sure is possible. But I don't know how one could easily demonstrate compliance.

I support the 'Option 3' version of C6.3.1.15(a)(ii) and the 'Option 4' version of CC.6.3.15(b) (ii) & (iii) because they provide greater clarity. I can see that the 'Option 2' version of CC.6.3.1.15(c)(i) presents a potential problem because the retained voltage at the terminals of the individual generating units in a wind farm during a zero voltage transmission system fault will depend on the number of such generating units connected at the time, so that the retained voltage may be too low in the unusual circumstance of high wind speeds (so output is above 5%), but with a substantial number of turbines shut down. One solution would be to use the 'Option 2' words, but to make it clear that compliance with the requirements under these conditions would be on a best endeavours basis, with a derogation if the farm cannot quite meet the requirement under these circumstances.

Regards

David Ward

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--------------- End of message

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Date: **21 February 2005**

Gareth Evans
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Dear Gareth

Ref: Consultation 07/05
Grid Code changes to Incorporate New Generation Technologies and DC Inter-Connectors (Generic Provisions) – The Authorities 'Minded To' Decision Letter and Impact Assessment Relating to National Grid Company's H/04 Report to the Authority.

Thank you for the opportunity to respond to the Ofgem consultation relating to the Grid Code proposals contained in Report H/04. National Grid Company welcomes and supports Ofgem's "minded to" decision to approve the Grid Code changes proposed in H/04 as drafted in the GB Grid Code context and as amended by the Supplementary Changes included in Attachment 1 of the Ofgem consultation.

NGC welcomes Ofgem's support of the Fault Ride Through requirement and notes that the independent consultants SKM commissioned by Ofgem also support the requirement. The economic assessments made by Ofgem and the Centre for Distributed Generation and Sustainable Electrical Energy both support the Transmission Licensees' view that it is more cost effective to improve the performance of these types of generator systems than to compensate for them using system operational measures that incur a very considerable increase in operational costs. While Ofgem notes that the Fault Ride Through requirement is generally specified in a different manner to other European utilities, it should be noted that the physical nature and characteristics of a particular network and the required level of supply security determine both the form and content of the requirement.

NGC supports the views put forward by Ofgem regarding the provision of a frequency response capability and a reactive range capability along with voltage control. NGC also supports the views expressed on frequency range and negative phase sequence capabilities, as these are also key requirements for ensuring continued stable and secure operation of the transmission system.

NGC supports Ofgem's analysis and conclusions contained in their Impact Assessment. National Grid believes that the Impact Assessment provides a clear justification and support for Ofgem's "minded to" decision to approve the proposed Grid Code changes.

The survey of international wind turbine manufacturers conducted by the Transmission Licensees' 12 months ago and reproduced in Ofgem's Impact Assessment shows that the majority of manufacturers can supply wind turbines that are compliant with the Grid Code. While a few manufacturers may not yet be able to produce a fully compliant machine without further development, the manufacturer base for compliant wind turbines remains considerably larger than that for traditional large synchronous generating plant. Therefore NGC does not believe that the apparent restriction on supplier base will pose any material risk.

NGC supports Ofgem's view that an acceptable point has now been reached in the development of the Grid Code proposals, including the Supplementary Changes, that further modification is not required. It should be noted that following approval by Ofgem and implementation of the proposals, the GB Grid Code Review Panel can bring further incremental changes forward if required and as supported by experience gained in the future.

Finally, NGC supports Ofgem's proposed alignment of the implementation date for these Grid Code changes with the introduction of BETTA. This will resolve the issue of the application of the Connection Conditions to Small Generators in Scotland with whom National Grid does not have the necessary contractual relationship for effective implementation. However given the logistics of preparing and distributing amended Grid Code pages, especially for such a substantial change, NGC would like to discuss with Ofgem the practicalities of achieving implementation within one month of the closure of the Ofgem consultation.

Yours sincerely

David Payne

SP Transmission & Distribution

Gareth Evans
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Your ref

Our ref
Our Ref
DN
Date
25th February
Contact / Extension
David A C Nicol /
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Dear Gareth

Grid Code Consultations SA/2004 & H/04

SP Transmission (SPT) welcomes the two complementary consultations on SA/2004 and H/04. It is noted in the consultation paper SA/2004, that while the rapid growth of wind power is now well appreciated both within and outwith the electricity supply industry, it is now almost four years since the two Scottish Transmission Licensees initiated studies through the Scottish Grid Code Review Panel to identify the changes that should be made to the Scottish Grid Code.

Following this lengthy process, SPT remains strongly supportive of the underlying principals and proposals in the two consultation papers. Given the imminent introduction of BETTA, SPT also supports Ofgem's "minded to" position that the Scottish SA/2004 proposals will be achieved by incorporation into the GB Grid Code.

Within the consultation papers there are some supplementary change proposals and some specific questions. We provide our detailed position on these points in the attachment to this letter.

If you have any questions, please feel free to contact me

Yours sincerely

David A C Nicol.

David A C Nicol
SO/TO Workstream Manager

Consultations SA/2004 and H/04

SPT Transmission Ltd - Detailed Comments

Below SPT make some detailed comments about the two consultation papers.

General

SP Transmission generally welcomes the proposals in the two complementary consultation papers. We note that the two consultation papers covered proposals in respect of

i) Fault Ride Through
ii) Frequency Range
(iii) Frequency Control
(iv) Reactive Range and Voltage Control
(v) Negative Phase Sequence
(vi) Thresholds

SPT supports their inclusion in the proposed wording for the GB Grid Code.

Additionally, the NGC paper H/04 contained proposals for
(vii) DC Interconnectors
SPT generally supports the proposal that these requirements should apply to the whole of GB.

The Scottish consultation SA/2004 contained proposals in respect of
(viii) Ramp Rates
SPT agrees with Ofgem that in a GB context these proposals are not required.

Generation Capacity Thresholds

We agree with the general comment that a review of the different Generation thresholds within the GB Grid Code is beyond the scope of these consultations. We would agree that it was never the intention of the Scottish Transmission Licensees to impose the Scottish Grid Code conditions on generators smaller than 5MW within Scotland. We therefore support the proposal to modify the drafting to remove the phrase "in England and Wales" from the GB drafting in clause CC6.3.1

Power Frequency Characteristics for DC Converters

SPT notes that while the Scottish Transmission Licensees never formally discussed Grid Code drafting for DC Converters, it had been the intention of the SGCRP to introduce, in the fullness of time, appropriate requirements in the Scottish Grid Code. SPT therefore generally supports the extension of the NGC proposals to Scotland.

In respect of the detailed question re power/frequency characteristics of DC Converter stations, SPT supports the principle put forward by SKM that the power/frequency characteristic should align with that used by the emergency low frequency demand disconnection scheme.

The drafting in the GB Grid Code needs therefore take account of the fact that the current draft of the GB Grid Code allows for different proportions of demand to be shed in Scotland than in England and Wales (compare OC 6.6.1). The proposed wording should therefore be altered to be consistent with this.

Voltage Characteristics

SPT supports the proposals on voltage characteristics.

Governor Requirements

SPT supports the proposals in respect of manufacturers specification

Frequency Response

SPT supports the proposals in respect of frequency response, and the earlier dates for introduction in Scotland.

Fault Ride Through

There are several detailed options discussed in this section, and various improvements to the wording as put forward in SA/2004 and H/04. SPT accepts the general improvements to the wording through the splitting of various clauses.

SKM had suggested that the relaxation against fault ride through under high wind speed shutdown conditions was not supportable. SPT accepts that recommendation, but notes that the original proposal had been a compromise between the three transmission licensees and developers who wanted a broader relaxation. SPT could not have supported the broader relaxation originally requested by the developers, but would support either (i) the relaxation put forward in the consultation papers, or (ii) SKM's alternative.

SPT notes the discussion regarding timescales for "immediate power recovery" and "power recovery within 1 second". The proposed drafting of 0.5 seconds in CC6.3.15(a)(ii) appears to be an appropriate way forward.

SPT does not understand the discussion regarding the appropriateness of the requirement for proportionality of active power during a voltage dip on the supergrid. As the discussion notes, the retained voltage on an embedded system is likely to be higher than that on the supergrid. The proposed wording that active power should be proportional to the local voltage at the entry point to the embedded system, appears to us to be both (i) more onerous, and (ii) possibly unlikely to be achievable given the lower voltages on the supergrid system. We therefore query whether this proposal is practically achievable as compared to the original proposal.