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27 May 2005

Dear Colleague,

STANDARD CONDITION C14: TRANSMISSION LICENCE, LICENSEE'S GRID CODE

Decision and direction in relation to consultations H/04, "Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)" and SA/2004, "Consultation on Technical Requirements for Windfarms"

On 17 January 2005 Ofgem published its 'minded to' decisions (Ofgem document references 07/05[1] and 08/05[2]) in response to:

- NGC's[3] report to the Gas and Electricity Markets Authority (the "Authority")[4] arising from consultation H/04 ("Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)")[5]; and

- the Scottish transmission licensees' (Scottish Power Transmission Ltd (SPT) and Scottish Hydro-Electric Transmission Ltd (SHETL)) report to the Authority arising from consultation SA2004 ("Consultation on Technical Requirements for Windfarms")[6].

These two reports to the Authority were seeking approval for changes to the England & Wales Grid Code and the Scottish Grid Code. Ofgem's 'minded to' decisions were supported by a single Impact Assessment and a document titled "Supplementary Changes". This latter

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1 http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9815_0705.pdf
2 http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9816_0805.pdf
3 National Grid Company plc.
4 The terms "Ofgem" and "the Authority" are used interchangeably in this letter. Ofgem is the office of the Authority.
5 This is available on NGC's website at http://www.nationalgridinfo.co.uk/grid_code/mn_consultation_papers.html
6 This is available on SPT's website at http://gso.scottishpower.com/publicdocs/ and SHETL's website at http://www.scottish-southern.co.uk/ssegroup/PowerSystemsDocuments.asp

document, published for consultation, described a number of Grid Code change proposals additional to those contained in the H/04 and SA/2004 reports to the Authority and the reasons for them.

This letter sets out Ofgem's final decisions in relation to the H/04 and SA/2004 consultations. These decisions have been taken concurrently because on 1 April this year, the Scottish Grid Code ceased to exist as part of the BETTA implementation. Ofgem's decisions relating to the H/04 and SA/2004 consultations will therefore be enacted in the Grid Code that now applies throughout Great Britain.

Ofgem received fifteen responses to its consultation on its 'minded to' decision letters, Impact Assessment and the Supplementary Changes relating to SA/2004 and H/04. These have been published today except where confidentiality has been requested. Careful consideration has been given to all of these responses in reaching a final decision. Ofgem is aware of the impact that its decision could have both in terms of the security of the transmission system and the growth of renewable generation and has taken account of the views of all affected parties. Ofgem is also aware that a small number of objections to the proposals remain. However, Ofgem has now decided that the Grid Code changes proposed in the H/04 and SA/2004 reports to the Authority should now be incorporated in the Grid Code, together with:

- specific elements of the Supplementary Changes as consulted on (see Attachment 1); and
- certain Additional Changes, explained in this letter, which respond to the comments received through Ofgem's consultation (see Attachment 2).

Ofgem considers that all these changes are appropriate in the context of NGC's Grid Code objectives set out in condition C14.1(b)[7] of the Transmission Licence and Ofgem's principal objective and wider general duties.

This letter explains the background to the proposals and sets out the Authority's reasons for its decision to approve these changes to the Grid Code including the Additional Changes that Ofgem has discussed with the three GB transmission licensees (Attachment 2) who have offered their support for them. This letter constitutes notice by the Authority under Section 49A of the Electricity Act 1989 in relation to the directions contained or referred to in this letter.

In order to clearly distinguish between different versions of grid codes in this letter the following convention is applied. The term "Grid Code" refers to the grid code published by NGC on 1 September 2004 and all subsequent revisions. The grid code published by NGC prior to 1 September 2004 will be described as the England & Wales Grid Code. Reference is also made

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[7] The licensee's transmission licence defines the Grid Code objectives as follows:

(i) to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity;
(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the GB transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity); and
(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

to the Scottish Grid Code which applied in Scotland up to 31 March 2005 but which has now been replaced by the Grid Code.

Background to the proposed changes to the Grid Code

On 24 December 2002 the Scottish licensees submitted a 'Report to the Authority' relating to consultation SB/2002; "Proposed amendments for windfarms". Ofgem was aware at this stage that these proposals were not supported by all parties; in particular the wind generation community had raised objections to the change proposals. In order to better understand the proposals and the objections to them meetings were held with the licensees and wind generation representatives. In September 2003 a joint meeting was held between these parties and Ofgem. It was at this stage that the consultation processes in Scotland, England and Wales were effectively brought together. On 31 October 2003 NGC submitted a 'Report to the Authority' relating to consultation D/03 ("Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)"). Ofgem responded to NGC on 6 November 2003. In this letter Ofgem requested NGC to carry out further work to achieve two objectives. Firstly, Ofgem thought it would be beneficial for parties applying for connection, in particular because of the development of BETTA, for there to be a fully consistent approach adopted by NGC and the Scottish transmission licensees. Secondly, Ofgem encouraged the licensees to carry out further work with the affected stakeholders to address their concerns and wherever possible reach agreement about the change proposals.

Following Ofgem's letter a number of activities were initiated. Firstly, all three GB transmission licensees worked together to align the proposals for Scotland and England and Wales. This work was completed early in 2004. Secondly, a series of meetings with the major manufacturers of wind generators was arranged. At these meetings the licensees explained the aligned proposals and the manufacturers fed back their views on their ability to comply with them and the cost of doing so. Finally, Ofgem convened a Forum to discuss the aligned proposals in detail. Representatives of all affected parties were given a voice at the Forum and the notes of the two meetings held were published in full[8].

Following the Forum meetings, the licensees revised their England & Wales and Scottish Grid Code change proposals having given consideration to the views expressed. On 23 June 2004, NGC published Consultation Document H/04 and the Scottish licensees published Consultation Document SA/2004. These proposals built on those set out in SB/2002 and D/03 by incorporating the information and views presented to the licensees during this additional period of consultation. The H/04 and SA/2004 consultations closed on 21 July 2004. NGC received comments on the proposals from fourteen parties including seven from manufacturers of wind turbines and related equipment. The Scottish licensees received comments on the proposals from 8 parties including 3 from manufacturers of wind turbines and related equipment. Having considered and responded to these comments NGC and the Scottish licensees produced their H/04 and SA/2004 Reports to the Authority dated 27 August 2004 and 2 September 2004 respectively.

[8] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6794_ForumMinutesFinal.pdf
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7237_ForumII_FinalNotes.pdf

NGC's and the Scottish licensees' recommendations

NGC recommended that the Authority should approve the changes to its England & Wales Grid Code set out in their report to the Authority arising from consultation H/04 ("Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)"). The Scottish licensees recommended that the Authority should approve the changes to the Scottish Grid Code set out in the report to the Authority arising from consultation SA/2004 ("Report on Consultation SA/2004"). All three licensees also supported the Supplementary Changes (Attachment 1) that were consulted on by Ofgem as part of its 'minded to' decision of 17 January 2005 and now support the Additional Changes as set out in Attachment 2 to this decision letter.

Ofgem's Consideration of the H/04 and SA/2004 Reports to the Authority

Ofgem is aware of the importance of the issues raised by the H/04 and SA/2004 proposals. In order to provide technical support to Ofgem in making its decision, Ofgem appointed Sinclair Knight Merz (SKM) in March last year to review these proposals. SKM took part in the Forum meetings described above and produced a report on the H/04 and SA/2004 change proposals. This report offered support for Ofgem's 'minded to' decision but made a number of suggestions for improvements which were discussed with the licensees. With the support of the licensees these additional changes were consulted on as the "Supplementary Changes". It should be noted that SKM was not required to report on the GB Grid Code drafting that Ofgem consulted on with its H/04 and SA/2004 'minded to' decisions. Ofgem published the SKM report[9] with its 'minded to' decisions on 17 January 2005.

The H/04 proposals related to the England and Wales Grid Code. This was, from 1 September 2004, superseded by the Grid Code which is now the single Grid Code for the GB transmission system. The SA/2004 proposals related to the Scottish Grid Code. This was, from 1 April 2005, superseded by the application of the Grid Code as the single Grid Code for the GB transmission system. It follows therefore that the H/04 and SA/2004 proposals cannot be implemented in the England and Wales and Scottish Grid Codes as originally drafted. In order to assist Ofgem's consultation process on a GB basis, NGC produced a new version of the Grid Code incorporating the H/04 change proposals and the equivalent SA/2004 change proposals (submitted by the Scottish licensees) and this was published with Ofgem's 'minded to' decision letter. NGC's incorporation of the H/04 and SA/2004 proposals into the Grid Code was intended to have the same effect as they would have done had they been included separately in the England & Wales and Scottish Grid Codes. Ofgem's consultation provided an opportunity for parties to comment on the incorporation of the H/04 and SA/2004 proposals into the Grid Code. The consultation also gave an opportunity for parties to comment on the Supplementary Changes which had not been consulted on previously.

Based on its own analysis and the advice of its consultants, SKM, Ofgem reached 'minded to' decisions regarding the H/04 and SA/2004 change proposals and proposed Supplementary Changes which were set out and explained in its letters of 17 January 2005. Ofgem, as part of its decision-making process, also assessed the possible impacts of these 'minded to' decisions in its Impact Assessment (IA - Attachment 2 of Reference 10). This letter therefore considers the responses that Ofgem has received in response to its consultation and explains its final decision.

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[9] "New Generating Technologies and GB Grid Codes", SKM, December 2004.

Ofgem's view

Ofgem considers that, having had regard to NGC's Grid Code objectives set out in condition C14.1(b) of the Transmission Licence and Ofgem's principal objective and wider general duties, the changes proposed in the H/04 and SA/2004 Reports to the Authority should be approved, as incorporated in the Grid Code drafting published by NGC[10], subject to:

- the specific Supplementary Changes set out in Attachment 1 to this letter; and
- the Additional Changes set out in Attachment 2 to this letter.

Ofgem's reasons for reaching this decision are outlined below.

The first issue considered by Ofgem was the fundamental need for the H/04 and SA/2004 change proposals. Ofgem accepts the view taken by the licensees that the original drafting of the England & Wales and Scottish Grid Codes made the implicit assumption that all generators connecting to the transmission system would be synchronous plant. Ofgem accepts therefore that the Grid Code does need to be updated to recognise explicitly the particular characteristics of non-synchronous generating plant that parties are now seeking to connect to the transmission system at an increasing rate. The Forum discussions confirmed that all affected parties support this view and Ofgem's consultation has confirmed this position.

Ofgem's views on the main technical issues are discussed below and this is followed by a commentary on the capacity and timing thresholds in these proposals. This section follows same format as 17 Jan 2005 minded to consultation but also deals with comments made on the 'minded to' letters.

i) Fault Ride Through (FRT)

NGC, acting in the role of GB System Operator, is required under its licence to at all times have in force and to implement and comply with a Grid Code designed so as to promote, amongst other things, the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole[11]. One of the generator performance characteristics necessary to achieve this is the ability to remain connected to the grid and continue to generate when faults occur on the transmission system. This is referred to as Fault Ride Through capability. The synchronous generators that have dominated the plant mix to date have an inherent ability to remain connected to the system when transmission faults occur. There has therefore never been a need formally to require an FRT capability to be provided via the grid codes.

Non-synchronous generators do not have the same inherent ability to withstand the disturbances resulting from system faults. If a significant tranche of such plant is connected to the system that is susceptible to tripping as a result of credible transmission faults the fundamental security of the system will be diminished. Ofgem recognises that this could be addressed by providing an increasing capacity of reserve plant but this approach would result in a number of adverse economic and environmental impacts. These impacts were discussed in the IA. Ofgem has

[10] http://www.nationalgrid.com/uk/indinfo/grid_code/pdfs/GB_Text_Extracts_050105.pdf
[11] Licence condition C14.1 (b) (iii) refers.

concluded that the introduction of an FRT requirement has merits which would ultimately benefit consumers. Ofgem therefore accepts that an FRT requirement should be introduced in the Grid Code for all plant.

There has been much discussion about the details of the FRT requirement and the ability of manufacturers to provide plant that can comply with the requirement. The survey of manufacturers carried out by the GB transmission licensees in early 2004 indicated that the majority of manufacturers could already or would soon be able to meet the FRT requirement proposed without material cost increases. The transmission licensees took account of the feedback from manufacturers before publishing their H/04 and SA/2004 proposals for consultation. Ofgem's independent consultants were supportive of the proposed H/04 and SA/2004 requirement[12] and have reported that it is broadly consistent with equivalent requirements being introduced by other transmission operators internationally. However, the consultants commented that the drafting of the FRT provision lacked clarity and recommended that the provisions should be redrafted to address this. The licensees responded to this and the Supplementary Changes document proposed revised drafting of the FRT provisions. This revised drafting received support from two respondents to Ofgem's consultation.

However, a number of respondents to Ofgem's consultation have raised objections to specific details of the proposed FRT requirement. The most significant comments are that:

- the requirement is more onerous than the equivalent requirements in Germany and Denmark;
- the implementation of the requirement could be delayed without affecting system security;
- the need for the specified rate of active power recovery has not been demonstrated;
- the use of the 400/275 kV transmission system fault location as the voltage reference point makes preliminary design more difficult; and
- several manufacturers are still unable to provide equipment that meets the requirement.

These points are discussed in turn here.

Comparison with other Grid Codes

Ofgem believes that comparisons with grid codes applying to other systems are useful. However, Ofgem recognises that different power systems have different characteristics and it cannot therefore be assumed that their grid code requirements should be the same. The power systems in Denmark and Germany are part of the much larger European grid that is potentially more resilient to generation loss than the GB system. It follows therefore that the FRT requirements can be different and, in certain respects, less onerous than for the GB system.

Potential for delay in implementation

Ofgem holds the view that the Grid Code requirements must be justified by system need. Following responses to the 'minded to' consultation, Ofgem requested the GB transmission licensees to provide further evidence to support the timing of the introduction of the FRT proposals. The GB transmission licensees responded by producing study results relating to credible system scenarios for 2005/6 and 2006/7. These studies demonstrate that there is a risk

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12 "New Generating Technologies and GB Grid Codes", SKM, December 2004.

of demand disconnection for credible system faults if all the contracted wind generation capacity was unable to offer FRT capability. Ofgem accepts that the risk of such incidents is very low. However, the security standards that the GB transmission licensees have to comply with do not permit a probabilistic assessment of the risk of loss of supply. Licence obligations therefore require them to ensure that the system is secure for worst case credible fault situations and it is these events that justify the introduction of an FRT requirement in the timescales proposed.

Active power recovery rate

Ofgem has also explored with the GB transmission licensees the need for the active power recovery rate proposed in the SA/2004 and H/04 proposals for FRT. It should be noted that by adopting the specific Supplementary Changes set out in this decision letter greater clarity has been achieved regarding active power recovery. Ofgem requested and has been provided with evidence that demonstrates the need for the rates proposed by the GB transmission licensees. Ofgem has therefore decided to support this requirement on the basis that a relaxation or delay could put the licensees at risk of not meeting their licence obligations. This approach also provides certainty and sustainability (i.e. it is unlikely that NGC will need to revisit this requirement in the near-term) going forward.

Voltage reference

Ofgem has noted that the proposed FRT requirement is specified in a different way to that adopted by grid operators in Ireland (ESB) and Germany (E.ON). This difference relates to the specification of the transmission system voltage depressions that plant must be resilient to. There is no fundamental reason why the same approach should be used by all grid operators but if comparisons showed significant differences they should be examined and understood. Ofgem's consultants considered this issue and advised that the licensees' proposals could be considered to be equivalent in practice to those applied in Germany and Ireland. Ofgem has considered this issue further before making its decision. It is necessary to specify clearly the fault condition that the generator must be resilient to. Specifying the voltage at the fault location achieves this. However, this approach does not directly inform the generator of the voltage that will be seen at the connection point of the wind farm or the wind turbine generator's (WTG) terminals. These voltages will always be specific to a particular connection. Initial calculations can be made using typical network data. Accurate calculations can be made using information contained in the Seven Year Statement advised by the NGC as required. From a technical point of view, the retained voltage at the WTG terminals is dependent on the magnitude of the fault current supplied by the WTG and the wind farm network and transformer impedances up to the fault location which is at 400kV or 275kV. Both of those factors are within the control of the developer and his supplier who can choose appropriate values of impedances and fault current magnitudes as and if required. The approach adopted by NGC is therefore considered acceptable.

Manufacturers' ability to meet the requirements

Ofgem has taken account of the views of the manufacturers and the evidence presented by NGC relating to the agreements being reached with respect to the technical capability of wind generators to meet FRT requirements. Ofgem accepts that the proposed Grid Code requirements are challenging for manufacturers. There is evidence that a minority of manufacturers may not be able to meet the requirements in full as of today. However, by setting out clearly the performance required in the Grid Code manufacturers will be able to implement any technical developments necessary to achieve compliance for their products.

FRT decision

NGC, acting in the role of GB System Operator, is required under its licence to at all times have in force and to implement and comply with a Grid Code designed so as to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole[13]. To do this, a power system must be resilient to credible faults. The transmission licensees are required to meet specific deterministic standards of performance in relation to the unplanned loss of generation. The consequences of failing to meet these standards can result in the emergency disconnection of demand on a national scale. The FRT proposals made by the GB transmission licensees are designed to ensure that the system maintains an acceptable level of resilience in the context of the growing penetration of wind generation. Ofgem has therefore decided to support the FRT proposals as modified by the Supplementary Changes set out in Attachment 1 (SC6 including Options 3 and 4) and the Additional Changes proposed by Ofgem and supported by the GB transmission licensees and set out in Attachment 2 (ACs 2, 3, 4 & 5). These Additional Changes have been included in response to specific comments made. They are not material but are considered to enhance the clarity of the Grid Code drafting. The final drafting for FRT is presented in AC5.

ii) Frequency Range

The Grid Code already requires generators to be able to operate at frequencies above and below the nominal 50 Hz. This is to ensure that generation is able to continue to contribute towards meeting demand in exceptional operating circumstances. Like FRT, this requirement is founded on the need to ensure supply security.

The application of this requirement to non-synchronous generators has not been a contentious issue and the manufacturers have confirmed that their equipment can meet this requirement. Ofgem therefore approves this element of the overall proposals on the basis that it is necessary in the context of NGC's licence objective to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

iii) Frequency Control

Ofgem recognises 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 Ofgem considers that it will become so as wind farm projects increase in size and their overall penetration increases. The argument has been made that the current Renewables Obligation Certificate (ROC) payments will make it commercially unattractive for wind generators to provide this service and that the capability should not be made a requirement. However, there is a possibility that at times of low system demand the ability of wind farms to provide frequency control may reduce the occasions when such plant will need to be constrained off the system. It is also possible that the wind farms now being planned will be operating after the ROC scheme ends so that the ability to provide frequency control may be both technically and commercially desirable.

[13] Licence condition C14.1 (b) (iii) refers.

No fundamental objections were made to the licensees' proposals. However, two parties argued for a delay in their implementation on the basis that the capability had yet to be demonstrated and that they were not yet necessary.

Ofgem has discussed this further with the licensees. Evidence has been produced by the licensees to show that this capability has been demonstrated and that wind farms currently under development have been able to meet this requirement. Ofgem has therefore decided to confirm its 'minded to' decision to approve the Grid Code change proposals with respect to frequency control on the basis that it is necessary in the context of NGC's licence objective to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

iv) Reactive Range & Voltage Control

The control of system voltage within statutory limits requires that sources of controllable reactive power are available across the system at various voltage levels. Generating plant has traditionally been the preferred source of reactive power.

Ofgem understands that the inherent ability of a non-synchronous generator to produce and absorb reactive power is related to each machine's specific design. However, for generators that have a limited capability, auxiliary plant can be provided so that a pre-defined overall capability can be achieved. Comments have been made about the relationship of real and reactive output. In response to Ofgem's consultation a proposal has been made to reduce the requirement to absorb reactive power when operating between 50%-20% output. Ofgem notes that the licensees' proposal for non-synchronous generators is somewhat less onerous than for synchronous machines and that a relaxation has been incorporated for outputs below 20%.

Ofgem is aware that the need for reactive power capability varies with electrical location. It is also quite likely that the system need could change through the life of a wind farm due to local system developments. It is also important to note that, unlike conventional generators, wind turbines are quite likely to operate at part-load for considerable periods of time. However, Ofgem believes that unnecessary over-engineering should be avoided wherever possible and we have therefore decided to direct the licensees that a modification to the reactive power requirement for non-synchronous generators will be made. This revised requirement is supported by the GB transmission licensees and is set out in Attachment 2 to this letter (AC1).

Ofgem has therefore decided the reactive range and voltage control proposals made by the licensees as modified according to Attachment 2 should be approved on the basis that they are necessary in the context of NGC's licence objective to at all times have in force and to implement and comply with a Grid Code designed so as to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

v) Negative Phase Sequence (NPS)

No material comments were received from respondents to the H/04 and SA/2004 consultations relating to the proposals for NPS capability and no objections were raised in response to the Ofgem consultation. Ofgem therefore approves the proposals for NPS capability as presented in the proposals on the basis that they are necessary in the context of NGC's licence objectives, in particular to at all times have in force and to implement and comply with a Grid Code designed so as to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

vi) Thresholds & Timescales

Scotland

Some requirements in the Grid Code differ in relation to the size of a power station. The definitions of Small, Medium and Large Power Stations are different in all three transmission licensee areas. Ofgem has stated[14] that following the introduction of BETTA this matter needs to be developed further and this has not been considered within the scope of the H/04 and SA/2004 consultations.

The Scottish Grid Code proposals placed requirements on all power stations, regardless of size, but also provided that the application of certain requirements would be at the discretion of the transmission licensee. The incorporation of the SA/2004 proposals into the GB Grid Code resulted in a situation in Scotland where requirements would apply to all Small Power Stations without the associated discretion being available to the transmission licensee. This issue was addressed in the Supplementary Changes of the 'minded to letter' (SC1 in Attachment 1) which proposed to extend the exclusion which was proposed in H/04 for Small Power Stations in England & Wales to Small Power Stations in Scotland. This received support from respondents to the consultation and no objections. As part of the BETTA implementation, this Grid Code change was directed by Ofgem in its letter of 31 March 2005 titled, "Direction in relation to the application of Grid Code requirement Connection Conditions CC6.3 to Small Power Stations in Scotland". The reasons for this early implementation are explained in that decision letter.

The timescales proposed for the introduction of the SA/2004 requirements are different to the equivalent H/04 proposals. The Scottish licensees justify this on the basis that the growth of wind generation has been more rapid in Scotland than England & Wales and this trend is expected to continue. The timescale for the introduction of these requirements should be set by the needs of the grid system and the licensee's ability to meet its licence obligations.

England & Wales

For connections in England & Wales, all Small Power Stations (i.e. less than 50MW Power Park Modules (PPMs)) are excluded from the proposed requirements and licence exempt embedded generators are also not obliged to comply with the Grid Code by licence, although generators who are licence exempt and greater than 50MW are required to enter into a Licence Exempt Generation Agreement with NGC. NGC is proposing that certain elements of the proposed changes are introduced from 1 January 2006 on the basis that this is necessary for it to meet its licence obligations. The timescale for the introduction of these requirements should be set by the needs of the grid system and the licensee's ability to meet its licence obligations. Setting this timescale is not a precise science as the actual rate of new plant commissioning is not in the licensee's control. The impact of the introduction of these proposals was explored in Ofgem's IA.

[14] Treatment of Embedded Exemptable Large Power Stations under BETTA – November 2004

Scotland, England & Wales

Ofgem understands that a number of non-synchronous generators that are required to comply with the Grid Code have either accepted connection offers or connected to the GB system prior to this decision in relation to the H/04 and SA/2004 consultations. The licensees have advised Ofgem that in these cases either:

- the required connection requirements have been agreed in writing (the approach in England & Wales); or
- the connecting party has been advised that the connection requirements to be imposed at the date of connection would be those being proposed at the date of the connection offer (this is the approach adopted in Scotland e.g. a connection offer made in Scotland in December 2004 would require compliance with the SA/2004 proposals).

Ofgem holds the view that its decision should not cause a material change to the requirements on any connected party or any party that has accepted a connection offer on or before the date of this decision letter. If any such party can demonstrate that it is subject to such a material change as a result of this decision then Ofgem will give consideration, in accordance with its published guidance, to granting a derogation to remedy the situation.

On this basis Ofgem accepts the case that the licensees have put forward on this element of the overall proposals and approves the capacity and timescale thresholds proposed by them.

vii) DC Interconnectors

The H/04 consultation process also proposed that explicit requirements should be included in the Grid Code for DC Interconnectors. These proposals had not been consulted on in a Scottish context previously and so Ofgem highlighted this issue in its 17 January 2005 'minded to' letter as a GB consultation issue. These requirements will only apply to DC Interconnectors with a completion date after 1 April 2005 and so will not impact on either of the existing DC Interconnectors into the GB system.

SKM raised an issue with respect to the DC Interconnector proposals. NGC considered SKM's comments and was supportive of a modification to the H/04 drafting. This was addressed in the Supplementary Changes document (SC2). Two respondents supported the SKM modification and there were no objections.

Ofgem therefore accepts the H/04 proposals as modified by the SKM proposal (SC2) on the basis that they are necessary in the context of NGC's licence objective to at all times have in force and to implement and comply with a Grid Code designed so as to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

viii) Ramp rates

The SA/2004 proposals included requirements relating to allowable ramp rates; the maximum rate at which a generator may change its output. This requirement is not carried over in the

BETTA arrangements and therefore is not included in the Grid Code. There is therefore no need for Ofgem to decide on this issue.

ix) Supplementary Changes SC3, SC4 and SC5

These Supplementary Changes are of a minor nature as explained in Attachment 1 to Ofgem's 17 January 'minded to' decision letters. Ofgem has decided that these changes should be made on the basis that, although minor, they are considered to enhance the clarity of the Grid Code drafting and no party has objected to them.

x) Additional Changes

As a result of the responses to Ofgem's 'minded to' letters of 17 January Ofgem has proposed to the transmission licensees that a number of Additional Changes will be made to the Grid Code drafting. The transmission licensees support these Additional Changes and they are set out in Attachment 2 to this letter. They can be summarised as follows:

AC1 – makes a modification to CC.6.3.2 in respect of the leading capability of a Power Park Module at low power outputs. This modification is required to avoid unnecessary costs where a reduced leading capability is acceptable.
AC2 – makes a modification to Option 4 of SC6 which specifies the voltage reference point for active power recovery in CC.6.3.15. This modification is required to ensure consistency of approach for 132kV connections in Scotland.
AC3 – adds the drafting recognising the intermittency of wind in CC.6.3.15(b)(iii) to CC.6.3.15(b)(ii). This modification is required to explicitly recognise the intermittency of wind and the impact on active power output during 400/275 kV transmission system voltage dips.
AC4 – removes the last sentence of CC.6.3.15(c)(iii) on the basis that it is superfluous.
AC5 – clarifies the meaning of "constituent element" in CC.6.3.15(b). This modification is required to clearly define the requirements to maintain active power output from generation during and after faults and voltage dips without applying to auxiliary systems that do not impact active power output.
AC6 – AC8 – provide minor drafting changes to add clarity and consistency.

Ofgem therefore accepts these Additional Changes on the basis that they are necessary in the context of NGC's objective to at all times have in force and to implement and comply with a Grid Code designed so as to promote the security and efficiency of the electricity generation, transmission and distribution systems in Great Britain taken as a whole.

The further development of ancillary services markets

Since the initial development of the grid codes in Great Britain the principle has been adopted that all plant connected to the transmission system (and certain distribution connected generating plant) should meet the minimum performance requirements set out in the grid codes. These requirements relate to, amongst other things, the provision of ancillary services. As part of the development of the H/04 and SA/2004 proposals some parties have suggested the development of the ancillary services markets to allow generators to meet their obligations (for example, mandatory frequency response obligations) by purchasing services (either directly or via NGC) from other participants. This approach could reduce the need to impose wide ranging technical requirements through the grid codes.

Ofgem is committed to the development of efficient markets, wherever possible, and considers that there may be further scope for development of ancillary services markets. For example, on the 28 September 2004, Ofgem directed a modification to the Connection and Use of System Code (CUSC) to introduce further competition in the provision of mandatory frequency response[11]. The issue of the development of ancillary services markets to allow generators to buy out their obligations has been discussed in industry workgroups and is currently being taken forward under the remit of the Balancing Services Standing Group (BSSG). Ofgem welcomes the work being undertaken by the BSSG in this respect. However, at this stage no formal proposals have been raised. Ofgem would consider any proposal that is raised on the issue of buy out, on its individual merits, and, more generally, would welcome the development of market-based solutions for the provision of certain ancillary services where appropriate.

Ofgem recognises that there is an immediate need to provide clarity to parties developing generation projects that incorporate non-synchronous technologies regarding connection requirements. Ofgem therefore has taken the view that the further development of markets could not be guaranteed to deliver an acceptable outcome in the time available. However, this does not in any way preclude further market developments and Ofgem would encourage parties with such proposals to pursue them through existing industry forums.

The Authority's decision

Ofgem is aware of the considerable work that has been carried out to develop these important changes to the Grid Code. Ofgem considers that the views of all affected parties have been given proper consideration in developing these proposals. Ofgem is aware that a small number of objections to the proposals remain. However, the Authority has now decided to direct the changes to the Grid Code, in accordance with Section 49A of the Electricity Act 1989, described in this letter as follows:

- the Grid Code changes as detailed in the GB drafting published by NGC in support on the 17 January 'minded to' decision letters as modified and/or added to by;
- the Supplementary Changes set out in Attachment 1 to this letter; and
- the further detailed modifications set out in Attachment 2 to this letter.

In addition, all the date references to DC Converters and the "[Grid Code change implementation date]" or "[change implementation date]" references in the Grid Code for non synchronous generators will be harmonised to 1 April 2005. This conforms to Ofgem's "minded to" decision, and makes the Grid Code more consistent whilst not having any material impact on users.

It should be noted that a number of unrelated changes have been made to the Grid Code since the 'minded to' drafting was published. This will have minor editorial impacts on specific sections of drafting but will not alter its effect.

Ofgem considers that these changes are appropriate in the context of NGC's objectives set out in condition C14.1(b) of the Transmission Licence ("the objectives") and Ofgem's principal objective and wider general duties.

While Ofgem has taken all reasonable steps to assess the impacts of its decision it has decided to monitor the actual impacts after a period of time. Ofgem will therefore hold a meeting of the Forum that has played such an important part in this process in approximately six months from the date of this decision. This will give all parties the opportunity to feedback actual experience of the application of these Grid Code changes.

The Authority's direction

Having regard to the above, the Authority, in accordance with standard licence condition C14 (4) of the licence to transmit electricity granted to NGC under Section 6 of the Electricity Act 1989 ('NGC's Transmission Licence'), hereby directs NGC to modify the Grid Code as set out in Attachment 3 to this letter with effect on and from 1 June 2005.

Please do not hesitate to contact me on the above number if you have any queries in relation to the issues raised in this letter or alternatively contact Gareth Evans on 020 7901 7347.

Yours sincerely

John Scott

John Scott
Technical Director
Signed on behalf of the Authority and authorised for that purpose by the Authority

Attachment 1

Grid Code Modifications H/04 & SA/2004

Supplementary Changes

(Changes consulted on as part of Ofgem's 17 January H/04 consultation)

May 2005

Introduction

The following Supplementary Changes are numbered SC1 to SC6 as referenced in the Decision Letter. The background to these changes was set out in Attachment 1 of Ofgem's 17 January 2005 'Minded To' letter.

SC1 - Generation Capacity Thresholds

CC.6.3.1 *This section sets out the technical and design criteria and performance requirements for **Generating Units**, **DC Converters** and **Power Park Modules** (whether directly connected to the **GB Transmission System** or **Embedded**) which each **Generator** or **DC Converter Station** owner must ensure are complied with in relation to its **Generating Units**, **DC Converters** and **Power Park Modules** but, does not apply to **Small Power Stations** or individually to **Power Park Units**. References to **Generating Units**, **DC Converters** and **Power Park Modules** in this CC.6.3 should be read accordingly.*

SC2 - Power Frequency Characteristic for DC Converters

CC.6.3.3 (d) *A **DC Converter Station** must be capable of maintaining its **Active Power** input (i.e. when operating in a mode analogous to **Demand**) from the **GB Transmission System** (or **User System** in the case of an **Embedded DC Converter Station**) at a level not greater than the figure determined by the linear relationship shown in Figure 3 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47.8 Hz the **Active Power** input decreases by more than 60%.*

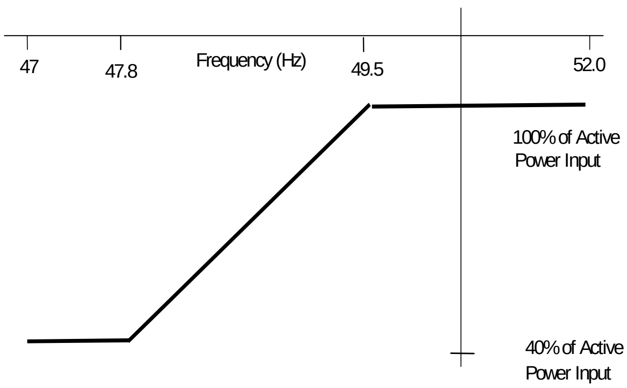


Figure 3

SC3 - Voltage Characteristic

The paragraph would therefore read as follows:

CC.6.3.4 *At the **Grid Entry Point** the **Active Power** output under steady state conditions of any **Generating Unit, DC Converter** or **Power Park Module** directly connected to the **GB Transmission System** should not be affected by voltage changes in the normal operating range specified in paragraph CC.6.1.4 by more than the change in **Active Power** losses at reduced or increased voltage. 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, except for a **Power Park Module** or **Non-synchronous Generating Unit** if **Embedded** at 33kV and below (or directly connected to the **GB Transmission System** in England and Wales at 33kV and below) where the requirement shown in Figure 4 applies.*

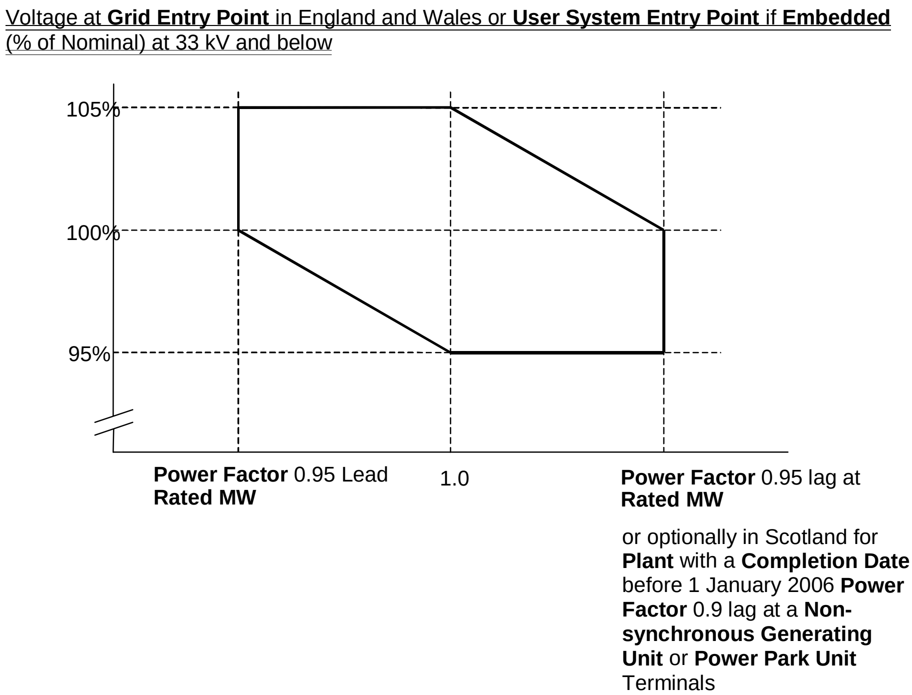


Figure 4

SC4 - Governor Requirements

CC.6.3.7 *(a)* *Each **Generating Unit, DC Converter** or **Power Park Module** (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 (which may include a manufacturer specification);*

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*

<u>**SC5** - Frequency Response</u>

CC.6.3.6 (a) *Each:*

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

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

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

…….

(e) ……..

(iii) *Each* ***Power Park Module*** *in operation in England and Wales with a* ***Completion Date*** *on or after 1 January 2006 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:-

…….

*(iii) **Power Park Modules** in England and Wales with a **Completion Date** before 1 January 2006 for whom only the requirements of **Limited Frequency Sensitive Mode** (BC.3.5.2) operation shall apply; or*

*(iv) **Power Park Modules** in operation in Scotland before 1 January 2006 for whom only the requirements of **Limited Frequency Sensitive Mode** (BC.3.5.2) operation shall apply; or*

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

……..

MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE AND OPERATING RANGE
for new Power Stations and DC Converter Stations

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 **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** in England and Wales with a **Completion Date** on or after 1 January 2006.*

*(d) each **Power Park Module** in operation in Scotland 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) ***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 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*** *in England and Wales with a* ***Completion Date*** *before 1 January 2006 and/or*

(iv) ***Power Park Modules*** *in operation in Scotland before 1 January 2006 or* ***Power Park Modules*** *in Scotland with a* ***Completion Date*** *before 1 April 2005 and* ***Power Park Modules*** *in Scotland in* ***Power Stations*** *with a* ***Registered Capacity*** *less than 30MW and/or*

(v) *To* ***Small Power Stations*** *or individually to* ***Power Park Units****.*

……..

BC3.5.3 …..

(b) Power Park Modules **in operation before 1 January 2006**
NGC will permit **Power Park Modules** in operation before 1 January 2006 to operate in **Limited Frequency Sensitive Mode** at all times. For the avoidance of doubt **Power Park Modules** in England and Wales with a **Completion Date** on or after 1 January 2006 and **Power Park Modules** in operation in Scotland after 1 January 2006 with a **Completion Date** after 1 July 2004 or in a **Power Station** with a **Registered Capacity** of 30MW and greater will be required to operate in both **Limited Frequency Sensitive Mode** and **Frequency Sensitive Mode** of operation depending on **System** conditions.

BC3.5.4 *Frequency Sensitive Mode*

(f) **NGC** will not so instruct **Generators** in respect of **Power Park Modules**:
(i) in Scotland with a **Completion Date** before 1 July 2004; or,
(ii) in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** of less than 30MW; or
(ii) in England and Wales with a **Completion Date** before 1 January 2006

<u>**SC6** - Fault Ride Through</u>

CC.6.3.15 Fault Ride Through

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

(i) *Each* ***Generating Unit, DC Converter,*** *or* ***Power Park Module*** *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).

(ii) Each __Generating Unit__ or __Power Park Module__ 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 restoration of the __Supergrid Voltage__ to the minimum levels specified in CC.6.1.4, __Active Power__ output shall be immediately 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.

(iii) 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] 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,

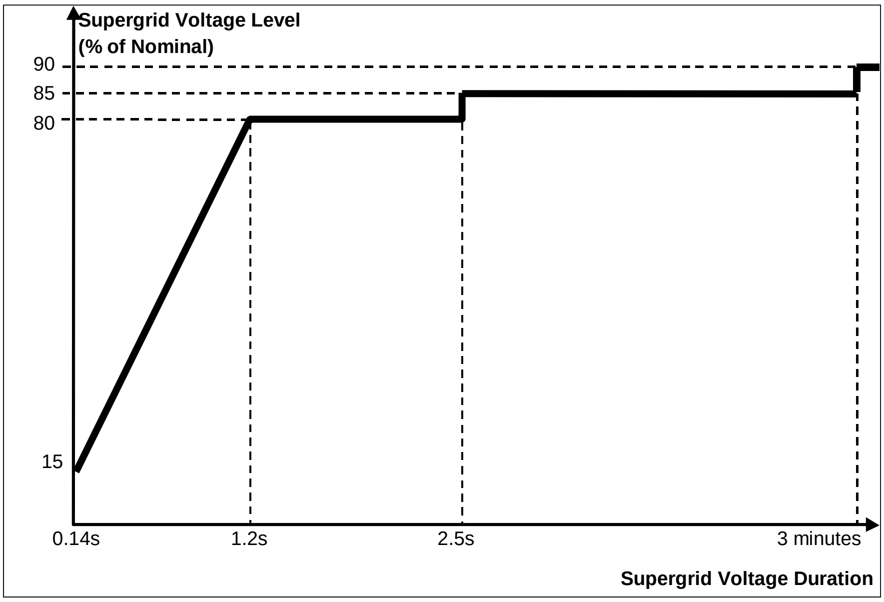


Figure 5

(ii) *provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced **Supergrid Voltage** 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,*

(iii) *restore **Active Power** output, following **Supergrid Voltage** dips as described in Figure 5, within 1 second of restoration of the **Supergrid Voltage** to the minimum levels specified in CC.6.1.4, 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***

(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**.*

(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****.*

(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.*

(iv) *To avoid unwanted island operation,* ***Non-Synchronous Generating Units*** *in Scotland or* ***Power Park Modules*** *in Scotland shall be tripped for the following conditions:-*

- (i) *Frequency above 52Hz for more than 2 seconds*
- (ii) *Frequency below 47Hz for more than 2 seconds*
- (iii) *Voltage as measured at the* ***Connection Point*** *or* ***User System Entry Point*** *below 80% for more than 2 seconds-*
- (iv) *Voltage as measured at the* ***Connection Point*** *or* ***User System Entry Point*** *above 120% (115% for 275kV) for more than 1 second.*

The times in sections (i) and (ii) are maximum trip times. Shorter times may be used to protect the ***Non-Synchronous Generating Units*** *or* ***Power Park Modules.***

SC6 - Option 2 – this is not to be included in the Grid Code.

SC6 - Option 3 Paragraph CC.6.3.15(a)(ii).

(ii) *Each* ***Generating Unit*** *or* ***Power Park Module*** *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.*

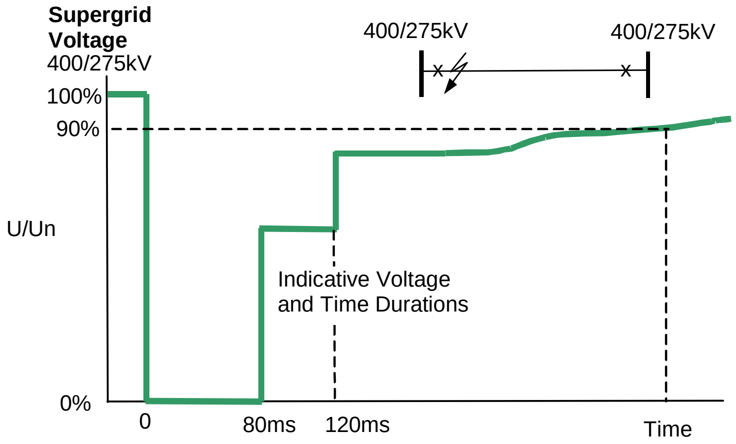
SC6 - Option 4 Paragraph CC.6.3.15(b)(ii) and (iii)

(ii) *provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced **Supergrid Voltage** (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,*

(iii) *restore **Active Power** output, following **Supergrid Voltage** dips as described in Figure 5, within 1 second of restoration of the **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.*

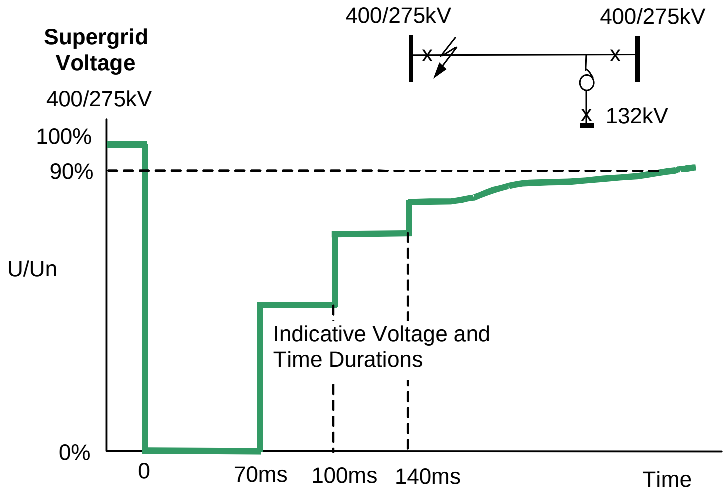
Appendix 4

SKM proposed that the illustrative figures in CC.A.4.2 be revised by removal of vertical arrows and addition of 400/275kV to the labels on the vertical axes. National Grid agrees and the revised the diagrams would appear as follows.



Typical fault cleared in less than 140ms: 2 ended circuit

Figure CC.A.4.1 (a)



Typical fault cleared in 140ms:- 3 ended circuit

Figure CC.A.4.1 (b)

Attachment 2

Grid Code Modifications H/04 & SA/2004

Additional Changes

(Changes resulting from the Ofgem consultation of 17 January 2005)

May 2005

Introduction

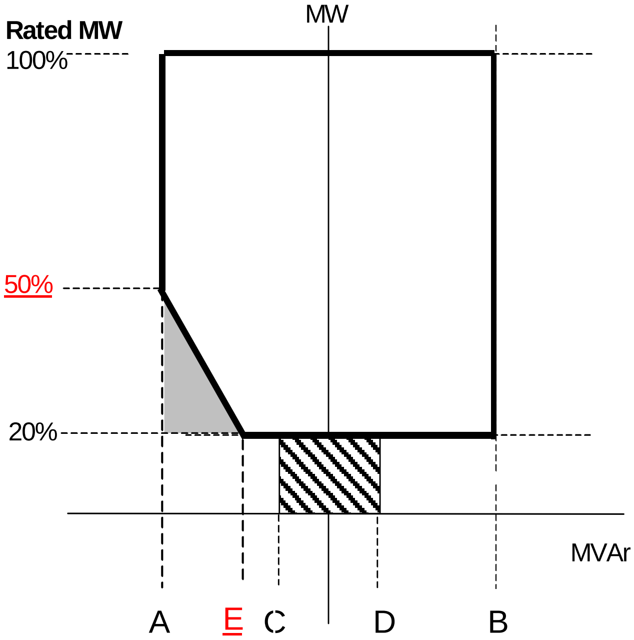
The following Additional Changes are numbered AC1 to AC8 as referenced in the Decision Letter.

Connection Conditions

AC1 – CC.6.3.2

……..

(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 (or **User System Entry Point** if **Embedded**). With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** <u>at Lagging **Power Factor**</u> will apply at all **Active Power** output levels above 20% of the **Rated MW** output as defined in Figure 1. <u>With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** will apply at all **Active Power** output levels above 50% of the **Rated MW** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure 1 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** down to 20% **Active Power** output is specified in the **Bilateral Agreement**.</u> 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*

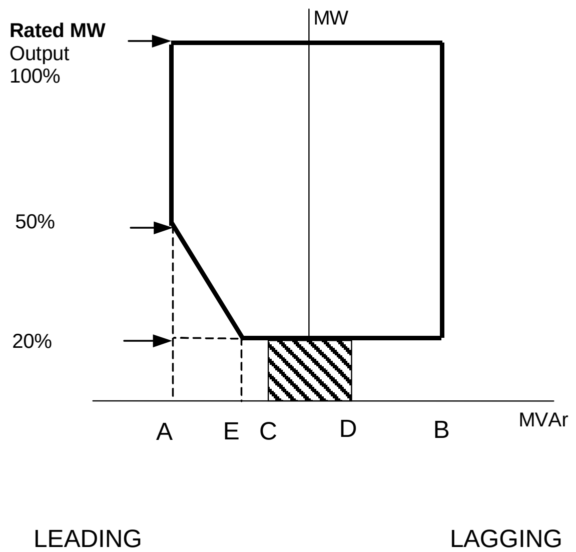
*Point C is equivalent (in MVAr) to: -5% of **Rated MW** output*
*Point D is equivalent (in MVAr) to: +5% of **Rated MW** output*

*Point E is equivalent (in MVAr) to: -12% of **Rated MW** output*

Figure 1

Operating Code 2 Appendix 1

POWER PARK MODULE PERFORMANCE CHART
AT THE CONNECTION POINT OR USER'S SYSTEM ENTRY POINT



*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*
*Point E is equivalent (in MVAr) to: -12% of **Rated MW** output*

AC2 – CC.6.3.15

(a)*(ii)* *Each **Generating Unit** or **Power Park Module** 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 voltage at the **Grid Entry Point** to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the **User System Entry Point** to 90% of nominal or* *greater if **Embedded**), **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 **Power Park Unit**.*

(b)*(ii)* *provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced ~~**Supergrid Voltage**~~ <u>voltage at the **Grid Entry Point**</u> (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,*

(b)(iii) *restore **Active Power** output, following **Supergrid Voltage** dips as described in Figure 5, within 1 second of restoration of the ~~**Supergrid Voltage**~~ <u>voltage at the **Grid Entry Point**</u> 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.*

AC3 – CC.6.3.15

(ii) *provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced **Supergrid Voltage** (or the retained balanced voltage at the **User System Entry Point** if **Embedded**) <u>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</u> 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,*

AC4 – CC.6.3.15

(c)(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.*~~

AC5 – CC.6.3.15

*(a)(i) Each **Generating Unit, DC Converter,** or **Power Park Module** and any constituent* **Power Park Unit** ~~*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* **Power Park Unit** ~~*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).*

*(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 **Power Park Unit**, each with a **Completion Date** on or after the [**Grid Code** change implementation date] shall:*

*(b)(i) remain transiently stable and connected to the **System** without tripping of any **Generating Unit** or **Power Park Module** and / or any* **Power Park Unit** ~~*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,*

*(b)(ii) provide **Active Power** output, during **Supergrid Voltage** dips as described in Figure 5, at least in proportion to the retained balanced **Supergrid Voltage** (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* **<u>Power Park Unit</u>** *~~constituent element~~; and,*

There is some interaction in the above change proposals particularly in CC.6.3.15(b)(ii). For clarity the complete paragraph CC.6.3.15 is reproduced below:

CC.6.3.15 <u>Fault Ride Through</u>

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

*(i) Each **Generating Unit, DC Converter,** or **Power Park Module** and any constituent **Power Park Unit** 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 **Power Park Unit**, 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).*

*(ii) Each **Generating Unit** or **Power Park Module** 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 voltage at the **Grid Entry Point** to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), **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 **Power Park Unit**.*

*(iii) 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 **Power Park Unit**, each with a **Completion Date** on or after the [**Grid Code** change implementation date] shall:*

*(i) remain transiently stable and connected to the **System** without tripping of any **Generating Unit** or **Power Park Module** and / or any **Power Park Unit**, 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,

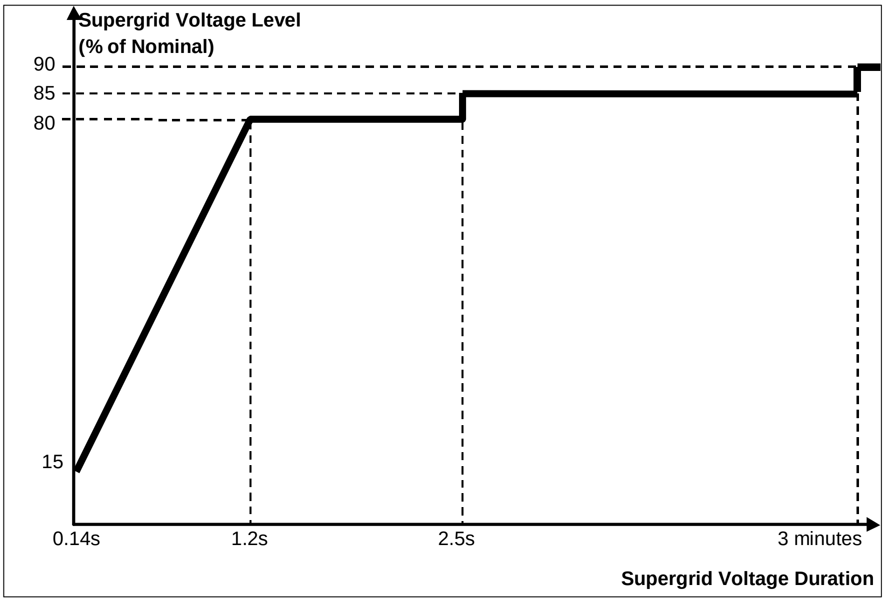


Figure 5

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

(iii) *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** 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***

(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**.*

(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 **Power Park Unit** 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**.*

(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.*

(iv) *To avoid unwanted island operation, **Non-Synchronous Generating Units** in Scotland or **Power Park Modules** in Scotland shall be tripped for the following conditions:-*

(1) *Frequency above 52Hz for more than 2 seconds*
(2) *Frequency below 47Hz for more than 2 seconds*
(3) *Voltage as measured at the **Connection Point** or **User System Entry Point** below 80% for more than 2 seconds~~-~~*
(4) *Voltage as measured at the **Connection Point** or **User System Entry Point** above 120% (115% for 275kV) for more than 1 second.*

*The times in sections (1) and (2) are maximum trip times. Shorter times may be used to protect the **Non-Synchronous Generating Units** or **Power Park Modules.***

AC6 – CC.A.3.1

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 **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** in England and Wales with a **Completion Date** on or after 1 January 2006.~~ and/or~~*

*(d) each **Power Park Module** in operation in Scotland 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) **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.~~ 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** in England and Wales with a **Completion Date** before 1 January 2006.~~ and/or~~*

*(iv) **Power Park Modules** in operation in Scotland before 1 January 2006. ~~or~~*

*(v) **Power Park Modules** in Scotland with a **Completion Date** before 1 April 2005. ~~and~~*

*(vi) **Power Park Modules** in Scotland in **Power Stations** with a **Registered Capacity** less than 30MW.~~ and/or~~*

*~~(v)~~(vii) ~~To~~ **Small Power Stations** or individually to **Power Park Units**.*

AC7 – Balancing Code 3

BC3.4.1 Statutory Requirements

*When **NGC** determines it is necessary (by having monitored the **System Frequency**), it will, as part of the procedure set out in **BC2**, issue instructions (including instructions for **Commercial Ancillary Services**) in order to seek to regulate **System Frequency** to meet the statutory requirements of **Frequency** control. **Gensets** (except those comprising of a **Power Park Module** in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** less than 30MW and those comprising of a **Power Park Module** in Scotland ~~in a **Power Station**~~ with a ~~**Registered Capacity** less than 100MW and a~~ **Completion Date** before 1 July 2004) and **DC Converters** at **DC Converter Stations** when transferring **Active Power** to the **Total System,** operating in **Frequency Sensitive Mode** will be instructed by **NGC** to operate taking due account of the **Target Frequency** notified by **NGC**.*

BC3.5.1 Capability

*Each **Genset** (except those comprising of **Power Park Modules** in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** less than 30MW and those comprising of **Power Park***

Modules *in Scotland* ~~*in a* ***Power Station***~~ *with a* ~~***Registered Capacity*** *less than 100MW and a*~~ ***Completion Date*** *before 1 July 2004) and each* ***DC Converter*** *at a* ***DC Converter Station*** *must at all times have the capability to operate automatically so as to provide response to changes in* ***Frequency*** *in accordance with the requirements of CC.6.3.7 in order to contribute to containing and correcting the* ***System Frequency*** *within the statutory requirements of* ***Frequency*** *control. For* ***DC Converters*** *at* ***DC Converter Stations, BC.3.1.3*** *also applies****.*** *In addition each* ***Genset*** *(and each* ***DC Converter*** *at a* ***DC Converter Station****) must at all times have the capability to operate in a* ***Limited Frequency Sensitive Mode*** *by operating so as to provide* ***Limited High Frequency Response****.*

AC8 – Balancing Code 3

BC3.5.3 …..

(b) **Power Park Modules** in operation before 1 January 2006

NGC will permit **Power Park Modules** in operation before 1 January 2006 to operate in **Limited Frequency Sensitive Mode** at all times. For the avoidance of doubt **Power Park Modules** in England and Wales with a **Completion Date** on or after 1 January 2006 and **Power Park Modules** in operation in Scotland after 1 January 2006 with a **Completion Date** after 1 July 2004 and ~~or~~ in a **Power Station** with a **Registered Capacity** of 30MW and greater will be required to operate in both **Limited Frequency Sensitive Mode** and **Frequency Sensitive Mode** of operation depending on **System** conditions.

Attachment 3

Grid Code Modifications H/04 & SA/2004

Grid Code Changes

May 2005

EXTRACTS FROM PREFACE

1. The operating procedures and principles governing **NGC's** relationship with all **Users** of the **GB Transmission System**, be they **Generators**, **DC Converter** owners, **Suppliers** or **Non-Embedded Customers** are set out in the **Grid Code**. The **Grid Code** specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

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3. The **Grid Code** is divided into the following sections:-

   (a) a **Planning Code** which provides generally for the supply of certain information by **Users** in order for **NGC** to undertake the planning and development of the **GB Transmission System**;

   (b) **Connection Conditions**, which specify the minimum technical, design and operational criteria which must be complied with by **NGC** at **Connection Sites** and by **Users** connected to or seeking connection with the **GB Transmission System** or by **Generators** (other than in respect of **Small Power Stations**) or **DC Converter** owners, connected to or seeking connection to a **User's System**;

EXTRACTS FROM GLOSSARY AND DEFINITIONS

Auxiliaries — Any item of **Plant** and/or **Apparatus** not directly a part of the boiler plant or **Generating Unit** or **DC Converter** or **Power Park Module**, but required for the boiler plant's or **Generating Unit's** or **DC Converter's** or **Power Park Module's** functional operation.

Control Centre — A location used for the purpose of control and operation of the **GB Transmission System** or **DC Converter Station** owner's **System** or a **User System** other than a **Generator's System** or an **External System**.

Control Person — The term used as an alternative to "**Safety Co-ordinator**" on the **Site Responsibility Schedule** only.

Control Phase — The **Control Phase** follows on from the **Programming Phase** and covers the period down to real time.

Control Point — The point from which:-

a) A **Non-Embedded Customer's Plant** and **Apparatus** is controlled; or

b) A **BM Unit** at a **Large Power Station** or at a **Medium Power Station** or representing a **Cascade Hydro Scheme** or with a **Demand Capacity** with a magnitude of 50MW or more (in England and Wales) or 5MW or more (in Scotland), is physically controlled by a **BM Participant**; or

c) In the case of any other **BM Unit** or **Generating Unit**, data submission is co-ordinated for a **BM Participant** and instructions are received from **NGC**,

as the case may be. For a **Generator** this will normally be at a **Power Station** but may be at an alternative location agreed with **NGC**. In the case of a **DC Converter Station**, the **Control Point** will be at a location agreed with **NGC**.. In the case of a **BM Unit** of an **Interconnector User**, the **Control Point** will be the **Control Centre** of the relevant **Externally Interconnected System Operator**.

DC Converter — Any **Apparatus** with a **Completion Date** after 1 April 2005 used to convert alternating current electricity to direct current electricity, or vice-versa. A **DC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, a **DC Converter** represents the bipolar configuration.

DC Converter Station	An installation comprising one or more **DC Converters** connecting a direct current interconnector: to the **NGC Transmission System;** or, (if the installation has a rating of 50MW or more) to a **User System**, and it shall form part of the **External Interconnection** to which it relates.
DC Network	All items of **Plant** and **Apparatus** connected together on the direct current side of a **DC Converter**.
Designed Minimum Operating Level	The output (in whole MW) below which a **Genset** or a **DC Converter** at a **DC Converter Station** (in any of its operating configurations) has no **High Frequency Response** capability.
De-Synchronise	a) The act of taking a **Generating Unit**, **Power Park Module** or **DC Converter** off a **System** to which it has been **Synchronised**, by opening any connecting circuit breaker; or b) The act of ceasing to consume electricity at an importing **BM Unit**; and the term "**De-Synchronising**" shall be construed accordingly.
Droop	The ratio of the steady state change in speed in the case of a **Generating Unit**, or in **Frequency** in the case a **Power Park Module**, to the steady state change in power output of the **Generating Unit** or **Power Park Module**.
External System	In relation to an **Externally Interconnected System Operator** means the transmission or distribution system which it owns or operates which is located outside **Great Britain** and any **Apparatus** or **Plant** which connects that system to the **External Interconnection** and which is owned or operated by such **Externally Interconnected System Operator**.
Generating Unit	Unless otherwise provided in the **Grid Code**, any **Apparatus** which produces electricity, including, ~~for the avoidance of doubt, a **CCGT Unit**.~~ a **Synchronous Generating Unit** and **Non-synchronous Generating Unit**.
Genset	A **Generating Unit**, **Power Park Module** or **CCGT Module** at a **Large Power Station** or any **Generating Unit** , **Power Park Module** or **CCGT Module** which is directly connected to the **GB Transmission System**.

Grid Entry Point — A point at which a **Generating Unit** or a **CCGT Module** or a **CCGT Unit** or a **DC Converter** or a **Power Park Module**, as the case may be, which is directly connected to the **GB Transmission System** connects to the **GB Transmission System**.

HV ~~Generator~~ Connections — **Apparatus** connected at the same voltage as that of the **GB Transmission System**, including **Users'** circuits, the higher voltage windings of **Users'** transformers and associated connection **Apparatus**.

Import Usable — That portion of **Registered Import Capacity** which is expected to be available and which is not unavailable due to a **Planned Outage**.

Intermittent Power Source — The primary source of power for a **Generating Unit** that can not be considered as controllable, e.g. wind, wave or solar.

Limited Frequency Sensitive Mode — A mode whereby the operation of the **Genset**(or **DC Converter** at a **DC Converter Station** exporting **Active Power** to the **Total System**) is **Frequency** insensitive except when the **System Frequency** exceeds 50.4Hz, from which point **Limited High Frequency Response** must be provided.

Limited High Frequency Response — A response of a **Genset** (or **DC Converter** at a **DC Converter Station** exporting **Active Power** to the **Total System**) to an increase in **System Frequency** above 50.4Hz leading to a reduction in **Active Power** in accordance with the provisions of BC3.7.2.

Minimum Generation — The minimum output (in whole MW) which a **Genset** can generate or **DC Converter** at a **DC Converter Station** can import or export to the **Total System** under stable operating conditions, as registered with **NGC** under the **PC** (and amended pursuant to the **PC**). For the avoidance of doubt, the output may go below this level as a result of operation in accordance with BC3.7.

Minimum Import Capacity — The minimum input (in whole MW) into a **DC Converter** at a **DC Converter Station** (in any of its operating configurations) at the **Grid Entry Point** (or in the case of an **Embedded DC Converter** at the **User System Entry Point**) at which a **DC Converter** can operate in a stable manner, as registered with **NGC** under the **PC** (and amended pursuant to the **PC**).

Mothballed DC Converter at a DC Converter Station — A **DC Converter** at a **DC Converter Station** that has previously imported or exported power which the **DC Converter Station** owner plans not to use to import or export power for the remainder of the current **Financial Year** but which could be returned to service.

Mothballed Power Park Module	A **Power Park Module** that has previously generated which the **Generator** plans not to use to generate for the remainder of the current **Financial Year** but which could be returned to service.
Non-Synchronous Generating Unit	A **Generating Unit** that is not a **Synchronous Generating Unit** including for the avoidance of doubt a **Power Park Unit**.
Operational Intertripping	The automatic tripping of circuit-breakers to prevent abnormal system conditions occurring, such as over voltage, overload, **System** instability, etc. after the tripping of other circuit-breakers following power **System** fault(s) which includes **System** to **Generating Unit**, **System** to **CCGT Module**, **System** to **Power Park Module, System** to **DC Converter** and **System** to **Demand** intertripping schemes.
Power Park Module	A collection of **Non-synchronous Generating Units** (registered as a **Power Park Module** under the **PC**) that are powered by an **Intermittent Power Source**, joined together by a **System** with a single electrical point of connection to the **GB Transmission System** (or **User System** if **Embedded**). The connection to the **GB Transmission System** (or **User System** if **Embedded**) may include a **DC Converter.**
Power Park Module Availability Matrix	The matrix described in Appendix 1 to BC1 under the heading **Power Park Module Availability Matrix.**
Power Park Module Planning Matrix	A matrix in the form set out in Appendix 4 of OC2 showing the combination of **Power Park Units** within a **Power Park Module** which would be expected to be running under normal conditions.
Power Park Unit	A **Generating Unit** within a **Power Park Module.**
Power Station	An installation comprising one or more **Generating Units** or **Power Park Modules** (even where sited separately) owned and/or controlled by the same **Generator**, which may reasonably be considered as being managed as one **Power Station**.
Rated MW	The "rating-plate" MW output of a **Generating Unit, Power Park Module** or **DC Converter**, being: (a) that output up to which the **Generating Unit** was designed to operate (Calculated as specified in **British Standard BS** EN 60034 – 1: 1995); or (b) the nominal rating for the MW output of a **Power Park Module** being the maximum continuous electric output power which the **Power Park Module** was designed to achieve under normal operating conditions; or (c) the nominal rating for the MW import capacity and export capacity (if at a **DC Converter Station**) of a **DC Converter**.

Registered Capacity

(a) In the case of a **Generating Unit** other than that forming part of a **CCGT Module** or **Power Park Module**, the normal full load capacity of a **Generating Unit** as declared by the **Generator**, less the MW consumed by the **Generating Unit** through the **Generating Unit's Unit Transformer** when producing the same (the resultant figure being expressed in whole MW).

(b) In the case of a **CCGT Module** or **Power Park Module**, the normal full load capacity of ~~a~~ the **CCGT Module** or **Power Park Module** (as the case may be) as declared by the **Generator**, being the **Active Power** declared by the **Generator** as being deliverable by the **CCGT Module** or **Power Park Module** at the **Grid Entry Point** (or in the case of an **Embedded CCGT Module** or **Embedded Power Park Module**, at the **User System Entry Point**), expressed in whole MW.

(c) In the case of a **Power Station**, the maximum amount of **Active Power** deliverable by the **Power Station** at the **Grid Entry Point** (or in the case of an **Embedded Power Station** at the **User System Entry Point**), as declared by the **Generator**, expressed in whole **MW**. The maximum **Active Power** deliverable is the maximum amount deliverable simultaneously by the **Generating Units** and/or **CCGT Modules** and/or **Power Park Modules** less the **MW** consumed by the **Generating Units** and/or **CCGT Modules** and/or **Power Park Modules** in producing that **Active Power**.

(d) In the case of a **DC Converter** at a **DC Converter Station**, the normal full load amount of **Active Power** transferable from a **DC Converter** at the **Grid Entry Point** (or in the case of an **Embedded DC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner, expressed in whole **MW**.

(e) In the case of a **DC Converter Station**, the maximum amount of **Active Power** transferable from a **DC Converter Station** at the **Grid Entry Point** (or in the case of an **Embedded DC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner, expressed in whole **MW**.

Registered Import Capability

In the case of a **DC Converter Station** containing **DC Converters** connected to an **External System**, the maximum amount of **Active Power** transferable into a **DC Converter Station** at the **Grid Entry Point** (or in the case of an **Embedded DC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter Station** owner, expressed in whole **MW**.

In the case of a **DC Converter** connected to an **External System** and in a **DC Converter Station**, the normal full load amount of **Active Power** transferable into a **DC Converter** at the **Grid Entry Point** (or in the case of an **Embedded DC Converter Station** at the **User System Entry Point**), as declared by the **DC Converter** owner, expressed in whole **MW**.

Slope — The ratio of the steady state change in voltage to the steady state change in **Reactive Power** output.

Station Transformer — A transformer supplying electrical power to the **Auxiliaries** of

- a **Power Station**, which is not directly connected to the **Generating Unit** terminals (typical voltage ratios being 132/11kV or 275/11kV),

or

- a **DC Converter Station**.

Synchronised

a) The condition where an incoming **Generating Unit or Power Park Module** or **DC Converter** or **System** is connected to the busbars of another **System** so that the **Frequencies** and phase relationships of that **Generating Unit, Power Park Module, DC Converter** or **System**, as the case may be, and the **System** to which it is connected are identical, like terms shall be construed accordingly.

b) The condition where an importing **BM Unit** is consuming electricity.

Synchronous Generating Unit — A **Generating Unit** including, for the avoidance of doubt, a **CCGT Unit** in which, under all steady state conditions, the rotor rotates at a mechanical speed equal to the electrical frequency of the **GB Transmission System** divided by the number of pole pairs of the **Generating Unit.**

System Constrained Capacity — That portion of **Registered Capacity** or **Registered Import Capacity** not available due to a **System Constraint**.

User System Entry Point — A point at which a **Generating Unit**, a **CCGT Module** or a **CCGT Unit**, or a **Power Park Module** or a **DC Converter**, as the case may be, which is **Embedded** connects to the **User System**.

< End of GD >

PLANNING CODE

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PC.3 SCOPE

PC.3.1 The **PC** applies to **NGC** and to **Users,** which in the **PC** means:

(a) **Generators**;

(b) **Network Operators**; ~~and~~

(c) **Non-Embedded Customers**~~.~~; and

(d) **DC Converter Station** owners**.**

The above categories of **User** will become bound by the **PC** prior to them generating, operating ,or consuming or importing/exporting, as the case may be, and references to the various categories (or to the general category) of **User** should, therefore, be taken as referring to them in that prospective role as well as to **Users** actually connected.

PC.3.2 In the case of **Embedded Power Stations** and **Embedded DC Converters**, unless provided otherwise, the following provisions apply with regard to the provision of data under this **PC**:

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(b) each **DC Converter** owner shall provide the data direct to **NGC** in respect of **Embedded DC Converter Stations**;

(~~b~~c) although data is not normally required specifically on **Embedded Small Power Stations** or on **Embedded** installations of direct current converters which do not form a **DC Converter Station** under this **PC**, each **Network Operator** in whose **System** they are **Embedded** should provide the data (contained in the Appendix) to **NGC** in respect of **Embedded Small Power Stations** or **Embedded** installations of direct current converters which do not form a **DC Converter Station** if:

(i) it falls to be supplied pursuant to the application for a **CUSC Contract** or in the **Statement of Readiness** to be supplied in connection with a **Bilateral Agreement** and/or **Construction Agreement,** by the **Network Operator**; or

(ii) it is specifically requested by **NGC** in the circumstances provided for under this **PC**.

PC.3.3 Certain data does not normally need to be provided in respect of certain **Embedded Power Stations** or **Embedded DC Converter Stations**, as provided in PC.A.1.12.

PC.4 PLANNING PROCEDURES

PC.4.1 Pursuant to Condition C11 of **NGC's Transmission Licence**, the means by which **Users** and proposed **Users** of the **GB Transmission System** are able to assess opportunities for connecting to, and using, the **GB Transmission System** comprise two distinct parts, namely:

(a) a statement, prepared by **NGC** under its **Transmission Licence**, showing for each of the seven succeeding **Financial Years**, the opportunities available for connecting to and using the **GB Transmission System** and indicating those parts of the **GB Transmission System** most suited to new connections and transport of further quantities of electricity (the "**Seven Year Statement**"); and

(b) an offer, in accordance with its **Transmission Licence**, by **NGC** to enter into a **CUSC Contract** for connection to (or, in the case of **Embedded Large Power Stations** ~~and~~ , **Embedded Medium Power Stations** and **Embedded DC Converter Stations**, use of) the **GB Transmission System**. A **Bilateral Agreement** is to be entered into for every **Connection Site** (and for certain **Embedded Power Stations** and for **Embedded DC Converter Stations**, as explained above) within the first two of the following categories and the existing **Bilateral Agreement** may be required to be varied in the case of the third category:

(i) existing **Connection Sites** (and for certain **Embedded Power Stations**, as detailed above) as at the **Transfer Date;**

(ii) new **Connection Sites** (and for certain **Embedded Power Stations** and for **Embedded DC Converter Stations**, as detailed above) with effect from the **Transfer Date**;

(iii) a **Modification** at a **Connection Site** (or in relation to the connection of certain **Embedded Power Stations** and for **Embedded DC Converter Stations**, as detailed above) (whether such **Connection Site** or connection exist on the **Transfer Date** or are new thereafter) with effect from the **Transfer Date**.

In this **PC**, unless the context otherwise requires, "connection" means any of these 3 categories.

....

PC.4.2.4 Clearly, an existing **User** proposing a new **Connection Site** (or **Embedded Power Station** or **Embedded DC Converter Station** in the circumstances outlined in PC.4.1) will need to supply data both in an application for a **Bilateral Agreement** and under the **PC** in relation to that proposed new **Connection Site** (or **Embedded Power Station** or **Embedded DC Converter Station** in the circumstances outlined in PC.4.1) and that will be treated as **Preliminary Project Planning Data** or **Committed Project Planning Data** (as the case may be), but the data it supplies under the **PC** relating to its existing **Connection Sites** will be treated as **Connected Planning Data**.

……

PC.4.3.1 Seven Year Statement

To enable the **Seven Year Statement** to be prepared, each **User** is required to submit to **NGC** (subject to the provisions relating to **Embedded Power Stations** and **Embedded DC Converter Stations** in PC.3.2) both the **Standard Planning Data** and the **Detailed Planning Data** as listed in parts I and 2 of the Appendix. This data should be submitted in calendar week 24 of each year (although **Network Operators** may delay the submission until calendar week 28) and should cover each of the seven succeeding **Financial Years** (and in certain instances, the current year). Where, from the date of one submission to another, there is no change in the data (or in some of the data) to be submitted, instead of re-submitting the data, a **User** may submit a written statement that there has been no change from the data (or in some of the data) submitted the previous time. In addition, **NGC** will also use the **Transmission Entry Capacity** and **Connection Entry Capacity** data from the **CUSC Contract** in the preparation of the **Seven Year Statement** and to that extent the data will not be treated as confidential.

……..

APPENDIX A

PLANNING DATA REQUIREMENTS

....

PC.A.1.2 ……..

(b) Where there is any change (or anticipated change) in **Committed Project Planning Data** or a significant change in **Connected Planning Data** in the category of **Forecast Data** or any change (or anticipated change) in **Connected Planning Data** in the categories of **Registered Data** or **Estimated Registered Data** supplied to **NGC** under the **PC**, notwithstanding that the change may subsequently be notified to **NGC** under the **PC** as part of the routine annual update of data (or that the change may be a **Modification** under the **CUSC**), the **User** shall, subject to PC.A.3.2.3 and PC.A.3.2.4, notify **NGC** in writing without delay.

………

(d) The routine annual update of data, referred to in (a)(iii) above, need not be submitted in respect of **Small Power Stations** or **Embedded** installations of direct current converters which do not form a **DC Converter Station** (except as provided in PC.3.2.(~~b~~c)), or unless specifically requested by **NGC**, or unless otherwise specifically provided.

……….

PC.A.1.6 The following paragraphs in this Appendix relate to **Forecast Data**:

3.2.2(b), ~~and~~ (h),(i) and (j)
4.2.1
4.3.1
4.3.2
4.3.3
4.3.4
4.3.5
4.5(a)(ii) and (b)(ii)
4.7.1
5.2.1
5.2.2
5.~~5~~6.1

PC.A.1.7 The following paragraphs in this Appendix relate to **Registered Data** and **Estimated Registered Data**:

2.2.1
2.2.4
2.2.5
2.2.6
2.3.1
2.4.1
2.4.2

3.2.2(a), (c), (d), (e), (f), ~~and~~ (g), (i)(part) and (j)
3.4.1
3.4.2
4.2.3
4.5(a)(i), (a)(iii), (b)(i) and (b)(iii)
4.6
5.3.2
5.4
5.4.2
5.4.3
5.5
5.~~5~~6.3
6.2
6.3

………

PC.A.1.12 Certain data does not need to be supplied in relation to **Embedded Power Stations** or **Embedded DC Converter Stations** where these are connected at a voltage level below the voltage level directly connected to the **GB Transmission System** except in connection with a **CUSC Contract**, or unless specifically requested by **NGC**.

PART 1

STANDARD PLANNING DATA

PC.A.2 **USER'S SYSTEM** DATA

PC.A.2.1 Introduction

PC.A.2.1.1 Each **User**, whether connected directly via an existing **Connection Point** to the **GB Transmission System,** or seeking such a direct connection, shall provide **NGC** with data on its **User System** which relates to the **Connection Site** and/or which may have a system effect on the performance of the **GB Transmission System**. Such data, current and forecast, is specified in PC.A.2.2 to PC.A.2.5. In addition each **Generator** with **Embedded Large Power Stations** or **Embedded Medium Power Stations** connected to the **Subtransmission System,** shall provide **NGC** with fault infeed data as specified in PC.A.2.5.5, and each **DC Converter** owner with **Embedded DC Converter Stations** connected to the **Subtransmission System** shall provide **NGC** with fault infeed data as specified in PC.A.2.5.6.

PC.A.2.1.2 Each **User** must reflect the system effect at the **Connection Site(s)** of any third party **Embedded** within its **User System** whether existing or proposed.

PC.A.2.1.3 Although not itemised here, each **User** with an existing or proposed **Embedded Small Power Station** or **Medium Power Station** or **Embedded DC Converter Station** with a **Registered Capacity** of less than 100MW or an **Embedded** installation of direct current converters which does not form a **DC Converter Station** in its **User System** may, at **NGC's** reasonable discretion, be required to provide additional details relating to the **User's System** between the **Connection Site** and the existing or proposed **Embedded Small Power Station** or **Medium Power Station** or **Embedded DC Converter Station** or

Embedded installation of direct current converters which does not form a **DC Converter Station**.

PC.A.2.1.4 At **NGC's** reasonable request, additional data on the **User's System** will need to be supplied. Some of the possible reasons for such a request, and the data required, are given in PC.A.6.2, PC.A.6.4, PC.A.6.5 and PC.A.6.6.

PC.A.2.2 **User's System** Layout

PC.A.2.2.1 Each **User** shall provide a **Single Line Diagram**, depicting both its existing and proposed arrangement(s) of load current carrying **Apparatus** relating to both existing and proposed **Connection Points**.

PC.A.2.2.2 The **Single Line Diagram** (~~two~~ three examples are shown in Appendix B) must include all parts of the **User System** operating at **Supergrid Voltage** throughout **Great Britain** and, in Scotland, also all parts of the **User System** operating at 132kV, and those parts of its **Subtransmission System** at any **Transmission Site**. In addition, the **Single Line Diagram** must include all parts of the **User's Subtransmission System** throughout **Great Britain** operating at a voltage greater than 50kV, and, in Scotland, also all parts of the **User's Subtransmission System** operating at a voltage greater than 30kV, which, under either intact network or **Planned Outage** conditions:-

(a) normally interconnects separate **Connection Points**, or busbars at a **Connection Point** which are normally run in separate sections; or

(b) connects **Embedded Large Power Stations,** or **Embedded Medium Power Stations**, or **Embedded DC Converter Stations** connected to the **User's Subtransmission System**, to a **Connection Point.**

At the **User's** discretion, the **Single Line Diagram** can also contain additional details of the **User's Subtransmission System** not already included above, and also details of the transformers connecting the **User's Subtransmission System** to a lower voltage. With **NGC's** agreement, the **Single Line Diagram** can also contain information about the **User's System** at a voltage below the voltage of the **Subtransmission System**.

The **Single Line Diagram** for a **Power Park Module** must include all parts of the System connecting generating equipment to the **Grid Entry Point** or (**User System Entry Point** if **Embedded**). As an alternative the **User** may choose to submit a **Single Line Diagram** of an electrically equivalent system connecting generating equipment to the **Grid Entry Point** (or **User System Entry Point** if **Embedded**). An example of a **Single Line Diagram** for a **Power Park Module** electrically equivalent system is shown in Appendix B.

The **Single Line Diagram** must include the points at which **Demand** data (provided under PC.A.4.3.4) and fault infeed data (provided under PC.A.2.5) are supplied.

PC.A.2.2.3 The above mentioned **Single Line Diagram** shall include:

(a) electrical circuitry (ie. overhead lines, identifying which circuits are on the same towers, underground cables, power transformers, reactive compensation equipment and similar equipment); and

(b) substation names (in full or abbreviated form) with operating voltages.

In addition, for all load current carrying **Apparatus** operating at **Supergrid Voltage** throughout **Great Britain** and, in Scotland, also at 132kV, the **Single Line Diagram** shall include:-

(a) circuit breakers

(b) phasing arrangements.

PC.A.2.2.3.1 For the avoidance of doubt, the **Single Line Diagram** to be supplied is in addition to the **Operation Diagram** supplied pursuant to CC.7.4.

PC.A.2.2.4 For each circuit shown on the **Single Line Diagram** provided under PC.A.2.2.1, each **User** shall provide the following details relating to that part of its **User System:**

Circuit Parameters:

Rated voltage (kV)
Operating voltage (kV)
Positive phase sequence reactance
Positive phase sequence resistance
Positive phase sequence susceptance
Zero phase sequence reactance (both self and mutual)
Zero phase sequence resistance (both self and mutual)
Zero phase sequence susceptance (both self and mutual)

In the case of a **Single ~~L~~line Diagram** for a **Power Park Module** electrically equivalent system the data should be on a 100MVA base. Depending on the equivalent system supplied an equivalent tap changer range may need to be supplied. Similarly mutual values, rated voltage and operating voltage may be inappropriate.

PC.A.2.2.5 For each transformer shown on the **Single Line Diagram** provided under PC.A.2.2.1, each **User** shall provide the following details:

Rated MVA
Voltage Ratio
Winding arrangement
Positive sequence reactance
(max, min and nominal tap)
Positive sequence resistance
(max, min and nominal tap)
Zero sequence reactance

PC.A.2.2.5.1. In addition, for all interconnecting transformers between the **User's Supergrid Voltage System** and the **User's Subtransmission System** throughout **Great Britain** and, in Scotland, also for all interconnecting transformers between the

User's 132kV **System** and the **User's Subtransmission System** the **User** shall supply the following information:-

Tap changer range
Tap change step size
Tap changer type: on load or off circuit
Earthing method: Direct, resistance or reactance
Impedance (if not directly earthed)

PC.A.2.2.6 Each **User** shall supply the following information about the **User's** equipment installed at a **Transmission Site**:-

(a) Switchgear. For all circuit breakers:-

Rated voltage (kV)
Operating voltage (kV)
Rated 3-phase rms short-circuit breaking current, (kA)
Rated 1-phase rms short-circuit breaking current, (kA)
Rated 3-phase peak short-circuit making current, (kA)
Rated 1-phase peak short-circuit making current, (kA)
Rated rms continuous current (A)
DC time constant applied at testing of asymmetrical breaking abilities (secs)

(b) Substation Infrastructure. For the substation infrastructure (including, but not limited to, switch disconnectors, disconnectors, current transformers, line traps, busbars, through bushings, etc):-

Rated 3-phase rms short-circuit withstand current (kA)
Rated 1-phase rms short-circuit withstand current (kA).
Rated 3-phase short-circuit peak withstand current (kA)
Rated 1- phase short-circuit peak withstand current (kA)
Rated duration of short circuit withstand (secs)
Rated rms continuous current (A)

A single value for the entire substation may be supplied, provided it represents the most restrictive item of current carrying apparatus.

PC.A.2.3 Lumped **System** Susceptance

PC.A.2.3.1 For all parts of the **User's Subtransmission System** which are not included in the **Single Line Diagram** provided under PC.A.2.2.1, each **User** shall provide the equivalent lumped shunt susceptance at nominal **Frequency**.

PC.A.2.3.1.1 This should include shunt reactors connected to cables which are not normally in or out of service independent of the cable (ie. they are regarded as part of the cable).

PC.A.2.3.1.2 This should not include:

(a) independently switched reactive compensation equipment connected to the **User's System** specified under PC.A.2.4, or;

(b) any susceptance of the **User's System** inherent in the **Demand (Reactive Power)** data specified under PC.A.4.3.1.

PC.A.2.4 Reactive Compensation Equipment

PC.A.2.4.1 For all independently switched reactive compensation equipment, including that shown on the **Single Line Diagram**, not operated by **NGC** and connected to the **User's System** at 132kV and above in England and Wales and 33kV and above in Scotland, other than power factor correction equipment associated directly with **Customers' Plant** and **Apparatus**, the following information is required:

(a) type of equipment (eg. fixed or variable);

(b) capacitive and/or inductive rating or its operating range in Mvar;

(c) details of any automatic control logic to enable operating characteristics to be determined;

(d) the point of connection to the **User's System** in terms of electrical location and **System** voltage.

PC.A.2.4.2 **DC Converter Station** owners are also required to provide information about the reactive compensation and harmonic filtering equipment required to ensure that their **Plant** and **Apparatus** complies with the criteria set out in CC.6.1.5.

PC.A.2.5 Short Circuit Contribution to **GB Transmission System**

PC.A.2.5.1 General

(a) To allow **NGC** to calculate fault currents, each **User** is required to provide data, calculated in accordance with **Good Industry Practice**, as set out in the following paragraphs of PC.A.2.5.

(b) The data should be provided for the **User's System** with all **Generating Units**, **Power Park Units** and **DC Converters** **Synchronised** to that **User's System**. The **User** must ensure that the pre-fault network conditions reflect a credible **System** operating arrangement.

(c) The list of data items required, in whole or part, under the following provisions, is set out in PC.A.2.5.6. Each of the relevant following provisions identifies which data items in the list are required for the situation with which that provision deals.

The fault currents in sub-paragraphs (a) and (b) of the data list in PC.A.2.5.6 should be based on an a.c. load flow that takes into account any pre-fault current flow across the **Point of Connection** being considered.

Measurements made under appropriate **System** conditions may be used by the **User** to obtain the relevant data.

(d) **NGC** may at any time, in writing, specifically request for data to be provided for an alternative **System** condition, for example minimum plant, and the **User** will, insofar as such request is reasonable, provide the information as soon as reasonably practicable following the request.

PC.A.2.5.2 **Network Operators** and **Non-Embedded Customers** are required to submit data in accordance with PC.A.2.5.4. **Generators** and **DC Converter Station** owners are required to submit data in accordance with PC.A.2.5.5.

PC.A.2.5.3 Where prospective short-circuit currents on equipment owned, operated or managed by **NGC** are close to the equipment rating, and in **NGC's** reasonable opinion more accurate calculations of the prospective short circuit currents are required, then **NGC** will request additional data as outlined in PC.A.6.6 below.

PC.A.2.5.4 Data from **Network Operators** and **Non-Embedded Customers**

Data is required to be provided at each node on the **Single Line Diagram** provided under PC.A.2.2.1 at which motor loads and/or **Embedded Small Power Stations** and/or **Embedded Medium Power Stations** and/or **Embedded** installations of direct current converters which do not form a **DC Converter Station** are connected, assuming a fault at that location, as follows:-

The data items listed under the following parts of PC.A.2.5.6:-

(a) (i), (ii), (iii), (iv), (v) and (vi);

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c) - (f).

PC.A.2.5.5 Data from **Generators** and **DC Converter Station** owners

PC.A.2.5.5.1 For each **Generating Unit** with one or more associated **Unit Transformers**, the **Generator** is required to provide values for the contribution of the **Power Station Auxiliaries** (including **Auxiliary Gas Turbines** or **Auxiliary Diesel Engines**) to the fault current flowing through the **Unit Transformer(s)**.

The data items listed under the following parts of PC.A.2.5.6(a) should be provided:-

(i), (ii) and (v);

(iii) if the associated **Generating Unit** step-up transformer can supply zero phase sequence current from the **Generating Unit** side to the **GB Transmission System;**

(iv) if the value is not 1.0 p.u;

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c) - (f), and with the following parts of this PC.A.2.5.5.

PC.A.2.5.5.2 Auxiliary motor short circuit current contribution and any **Auxiliary Gas Turbine Unit** contribution through the **Unit Transformers** must be represented as a combined short circuit current contribution at the **Generating Unit's** terminals, assuming a fault at that location. In the case of a **Power Park Unit** in a **Power Park Module**, the combined short circuit contribution need only be provided for each type of **Power Park Unit** in the **Power Park Module.**

PC.A.2.5.5.3 If the **Power Station** or **DC Converter Station** has separate **Station Transformers**, data should be provided for the fault current contribution from each transformer at its high voltage terminals, assuming a fault at that location, as follows:-

The data items listed under the following parts of PC.A.2.5.6

(a) (i), (ii), (iii), (iv), (v) and (vi);

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(b) - (f).

PC.A.2.5.5.4 Data for the fault infeeds through both **Unit Transformers** and **Station Transformers** shall be provided for the normal running arrangement when the maximum number of **Generating Units**~~**Gensets**~~ are **Synchronised** to the **System** or when all the **DC Converters** at a **DC Converter Station** are transferring **Rated MW** in either direction. Where there is an alternative running arrangement (or transfer in the case of a **DC Converter Station**) which can give a higher fault infeed through the **Station Transformers**, then a separate data submission representing this condition shall be made.

PC.A.2.5.5.5 Unless the normal operating arrangement within the **Power Station** is to have the **Station** and **Unit Boards** interconnected within the **Power Station**, no account should be taken of the interconnection between the **Station Board** and the **Unit Board**.

PC.A.2.5.5.6 Auxiliary motor short circuit current contribution and any auxiliary **DC Converter Station** contribution through the **Station Transformers** must be represented as a combined short circuit current contribution through the **Station Transformers.**

PC.A.2.5.6 Data Items

(a) The following is the list of data utilised in this part of the **PC**. It also contains rules on the data which generally apply:-

(i) Root mean square of the symmetrical three-phase short circuit current infeed at the instant of fault, (I_1'');

(ii) Root mean square of the symmetrical three-phase short circuit current after the subtransient fault current contribution has substantially decayed, (I_1');

(iii) the zero sequence source resistance and reactance values of the **User's System** as seen from the node on the **Single Line Diagram** provided under PC.A.2.2.1 (or **Station Transformer** high voltage terminals or **Generating Unit** terminals or **DC Converter** terminals, as appropriate) consistent with the infeed described in PC.A.2.5.1.(b);

(iv) root mean square of the pre-fault voltage at which the maximum fault currents were calculated;

(v) the positive sequence X/R ratio at the instant of fault;

(vi) the negative sequence resistance and reactance values of the **User's System** seen from the node on the **Single Line Diagram** provided under PC.A.2.2.1 (or **Station Transformer** high voltage terminals, or **Generating Unit** terminals or **DC Converter** terminals if appropriate) if substantially different from the values of positive sequence resistance and reactance which would be derived from the data provided above.

(b) In considering this data, unless the **User** notifies **NGC** accordingly at the time of data submission, **NGC** will assume that the time constant of decay of the subtransient fault current corresponding to the change from I_1" to I_1', (T") is not significantly different from 40ms. If that assumption is not correct in relation to an item of data, the **User** must inform **NGC** at the time of submission of the data.

(c) The value for the X/R ratio must reflect the rate of decay of the d.c. component that may be present in the fault current and hence that of the sources of the initial fault current. All shunt elements and loads must therefore be deleted from any system model before the X/R ratio is calculated.

(d) In producing the data, the **User** may use "time step analysis" or "fixed-point-in-time analysis" with different impedances.

(e) If a fixed-point-in-time analysis with different impedances method is used, then in relation to the data submitted under (a) (i) above, the data will be required for "time zero" to give I_1". The figure of 120ms is consistent with a decay time constant T" of 40ms, and if that figure is different, then the figure of 120ms must be changed accordingly.

(f) Where a "time step analysis" is carried out, the X/R ratio may be calculated directly from the rate of decay of the d.c. component. The X/R ratio is not that given by the phase angle of the fault current if this is based on a system calculation with shunt loads, but from the Thévenin equivalent of the system impedance at the instant of fault with all non-source shunts removed.

PC.A.3 **GENERATING UNIT AND DC CONVERTER DATA**

PC.A.3.1 Introduction

Directly Connected

PC.A.3.1.1 Each **Generator** and **DC Converter Station** owner with an existing, or proposed, **Power Station** or **DC Converter Station** directly connected, or to be directly connected, to the **GB Transmission System**, shall provide **NGC** with data relating to that **Power Station** or **DC Converter Station**, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4.

Embedded

PC.A.3.1.2 (a) Each **Generator** and **DC Converter Station** owner with an existing, or proposed, **Embedded Large Power Station** and/or an **Embedded Medium Power Station** and/or **Embedded DC Converter Station** connected to the **Sub Transmission System**, shall provide **NGC** with data relating to that **Power Station** or **DC Converter Station**, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4.

(b) No data need be supplied in relation to any **Small Power Station** or any **Medium Power Station** or installations of direct current converters which do not form a **DC Converter Station**, connected at a voltage level below the voltage level of the **Subtransmission System** except:-

(i) in connection with an application for, or under, a **CUSC Contract**, or

(ii) unless specifically requested by **NGC** under PC.A.3.1.4.

……….

PC.A.3.1.4 (a) PC.A.4.2.4(b) and PC.A.4.3.2(a) explain that the forecast **Demand** submitted by each **Network Operator** must be net of the output of all **Small Power Stations** and **Medium Power Stations** and **Customer Generating Plant** and all installations of direct current converters which do not form a **DC Converter Station**, **Embedded** in that **Network Operator's System**. The **Network Operator** must inform **NGC** of the number of such **Embedded Power Stations** and such **Embedded** installations of direct current converters (including the number of **Generating Units** or **Power Park Modules** or **DC Converters**) together with their summated capacity.

(b) On receipt of this data, the **Network Operator** or **Generator** (if the data relates to **Power Stations** referred to in PC.A.3.1.2) may be further required, at **NGC's** reasonable discretion, to provide details of **Embedded Small Power Stations** and **Embedded Medium Power Stations** and **Customer Generating Plant** and **Embedded** installations of direct current converters which do not form a **DC Converter Station**, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4. Such requirement would arise where **NGC** reasonably considers that the collective effect of a number of such **Embedded Power Stations** and **Customer Generating Plants** and **Embedded** installations of direct current converters may have a significant system effect on the **GB Transmission System**.

PC.A.3.1.5 Where **Generating Units**, which term includes **CCGT Units**~~,~~ and **Power Park Modules**, and **DC Converters** are connected to the **GB Transmission System** via a busbar arrangement which is or is expected to be operated in separate sections, the section of busbar to which each **Generating Unit**, **DC Converter** or **Power Park Module** is connected is to be identified in the submission.

PC.A.3.2 Output Data

PC.A.3.2.1 (a) **Large Power Stations** and **Gensets**

Data items PC.A.3.2.2 (a), (b), (c), (d), (e), (f) and (h) are required with respect to each **Large Power Station** and each **Generating Unit** and **Power Park Module** of each **Large Power Station** and for each **Genset** (although (a) is not required for **CCGT Units** and (b), (d) and (e) are not normally required for **CCGT Units** and (a), (b), (c), (d), (e), (f) and (h) are not normally required for **Power Park Units**).

(b) **Embedded Small Power Stations** and **Embedded Medium Power Stations**

Data item PC.A.3.2.2 (a) is required with respect to each **Embedded Small Power Station** and **Embedded Medium Power Station** and each **Generating Unit** and **Power Park Module** of each **Embedded Small Power Station** and **Embedded Medium Power Station** (although (a) is not required for **CCGT Units** or **Power Park Units**).

(c) **CCGT Units/Modules**

(i) Data item PC.A.3.2.2 (g) is required with respect to each **CCGT Unit**;

(ii) data item PC.A.3.2.2 (a) is required with respect to each **CCGT Module**; and

(iii) data items PC.A.3.2.2 (b), (c), (d) and (e) are required with respect to each **CCGT Module** unless **NGC** informs the relevant **User** in advance of the submission that it needs the data items with respect to each **CCGT Unit** for particular studies, in which case it must be supplied on a **CCGT Unit** basis.

Where any definition utilised or referred to in relation to any of the data items does not reflect **CCGT Units**, such definition shall be deemed to relate to **CCGT Units** for the purposes of these data items. Any **Schedule** in the DRC which refers to these data items shall be interpreted to incorporate the **CCGT Unit** basis where appropriate;

(d) **Cascade Hydro Schemes**

Data item PC.A.3.2.2(i) is required with respect to each **Cascade Hydro Scheme**.

(e) **Power Park Units/Modules**

Data items PC.A.3.2.2 (j) is required with respect to each **Power Park Module.**

(f) **DC Converters**

Data items PC.A.3.2.2 (a), (b), (c), (d) (e) (f) (h) and (i) are required with respect to each **DC Converter Station** and each **DC Converter** in each **DC Converter Station.** For installations of direct current converters which do not form a **DC Converter Station** only data item PC.A.3.2.2.(a) is required.

PC.A.3.2.2 Items (a), (b), (d), (e), (f), (g), (h), ~~and~~ (i),(j) and (k) are to be supplied by each **Generator, DC Converter Station** owner or **Network Operator** (as the case may be) in accordance with PC.A.3.1.1, PC.A.3.1.2, PC.A.3.1.3 and PC.A.3.1.4. Item (c) is to be supplied by each **Network Operator** in all cases:-

(a) **Registered Capacity** (MW);

(b) **Output Usable** (MW) on a monthly basis;

(c) **System Constrained Capacity** (MW) ie. any constraint placed on the capacity of the **Embedded Generating Unit , Embedded Power Park Module,** or **DC Converter** at an **Embedded DC Converter Station** due to the **Network Operator's System** in which it is embedded. Where **Generating Units** (which term includes **CCGT Units**) , **Power Park Modules** or **DC Converters** are connected to a **Network Operator's User System** via a busbar arrangement which is or is expected to be operated in separate sections, details of busbar running arrangements and connected circuits at the substation to which the **Embedded Generating Unit, Embedded Power Park Module** or **Embedded DC Converter** is connected sufficient for **NGC** to determine where the **MW** generated by each **Generating Unit, Power Park Module** or **DC Converter** at that **Power Station** or **DC Converter Station** would appear onto the **GB Transmission System**;

(d) **Minimum Generation** (MW);

(e) MW obtainable from **Generating Units, Power Park Modules** or **DC Converters** at a **DC Converter Station** in excess of **Registered Capacity**;

(f) **Generator Performance Chart:**

(i) at the **Synchronous Generating Unit** stator terminals

(ii) at the electrical point of connection to the **GB Transmission System** (or **User System** if **Embedded**) for **a Non Synchronous Generating Unit** (excluding a **Power Park Unit), Power Park Module** and **DC Converter** at a **DC Converter Station**;

(g) a list of the **CCGT Units** within a **CCGT Module**, identifying each **CCGT Unit**, and the **CCGT Module** of which it forms part, unambiguously. In the case of a **Range CCGT Module**, details of the possible configurations should also be submitted, together:-

(i) (in the case of a **Range CCGT Module** connected to the **GB Transmission System)** with details of the single **Grid Entry Point** (there can only be one) at which power is provided from the **Range CCGT Module**;

(ii) (in the case of an **Embedded Range CCGT Module**) with details of the single **User System Entry Point** (there can only be one) at which power is provided from the **Range CCGT Module**;

Provided that, nothing in this sub-paragraph (g) shall prevent the busbar at the relevant point being operated in separate sections;

(h) expected running regime(s) at each **Power Station** or **DC Converter Station** and type of **Generating Unit**, eg. **Steam Unit**, **Gas Turbine Unit**, **Combined Cycle Gas Turbine Unit**, **Power Park Module, Novel Units** (specify by type), etc;

(i) a list of **Power Stations** and **Generating Units** within a **Cascade Hydro Scheme**, identifying each **Generating Unit** and **Power Station** and the **Cascade Hydro Scheme** of which each form part unambiguously. In addition:

(i) details of the **Grid Entry Point** at which **Active Power** is provided, or if **Embedded** the **Grid Supply Point(s)** within which the **Generating Unit** is connected;

(ii) where the **Active Power** output of a **Generating Unit** is split between more than one **Grid Supply Points** the percentage that would appear under normal and outage conditions at each **Grid Supply Point**.

(j) The following additional items are only applicable to **DC Converters** at **DC Converter Stations**.

Registered Import Capacity (MW);

Import Usable (MW) on a monthly basis;

Minimum Import Capacity (MW);

MW that may be absorbed by a **DC Converter** in excess of **Registered Import Capacity** and the duration for which this is available;

(k) the number and types of the **Power Park Units** within a **Power Park Module**, identifying each **Power Park Unit**, and the **Power Park Module** of which it forms part, unambiguously. In the case of a **Power Station** directly connected to the **GB Transmission System** with multiple **Power Park Modules** where **Power Park Units** can be selected to run in different **Power Park Modules**, details of the possible configurations should also be submitted.

PC.A.3.2.3 Notwithstanding any other provision of this PC, the **CCGT Units** within a **CCGT Module**, details of which are required under paragraph (g) of PC.A.3.2.2, can only be amended in accordance with the following provisions:-

(a) if the **CCGT Module** is a **Normal CCGT Module**, the **CCGT Units** within that **CCGT Module** can only be amended such that the **CCGT Module** comprises different **CCGT Units** if **NGC** gives its prior consent in writing. Notice of the wish to amend the **CCGT Units** within such a **CCGT Module** must be given at least 6 months before it is wished for the amendment to take effect;

(b) if the **CCGT Module** is a **Range CCGT Module**, the **CCGT Units** within that **CCGT Module** and the **Grid Entry Point** at which the power is provided can only be amended as described in BC1.A1.6.4.

PC.A.3.2.4 Notwithstanding any other provision of this **PC**, the **Power Park Units** within a **Power Park Module**, details of which are required under paragraph (j) of PC.A.3.2.2, can only be amended in accordance with the following provisions:-

(a) if the **Power Park Units** within that **Power Park Module** can only be amended such that the **Power Park Module** comprises different **Power Park Units** due to repair/replacement of individual **Power Park Units** if **NGC** gives its prior consent in writing. Notice of the wish to amend a **Power Park Unit** within such a **Power Park Module** must be given at least 4 weeks before it is wished for the amendment to take effect;

(b) if the **Power Park Units** within that **Power Park Module** can be selected to run in different **Power Park Modules** as an alternative operational running arrangement the **Power Park Units** within the **Power Park Module** and the **Grid Entry Point** at which the power is provided can only be amended as described in BC1.A.1.7.4.

PC.A.3.3. Rated Parameters Data

PC.A.3.3.1 The following information is required to facilitate an early assessment, by **NGC**, of the need for more detailed studies;

(a) for all **Generating Units**(excluding **Power Park Units**) and **Power Park Modules**:

Rated MVA
Rated MW
~~Direct axis transient reactance~~;

(b) for each ~~s~~**Synchronous Generating Unit**:

Short circuit ratio
Direct axis transient reactance;
Inertia constant (for whole machine), MWsecs/MVA;

(c) for each **Synchronous Generating Unit** step-up transformer:

Rated MVA
Positive sequence reactance (at max, min and nominal tap).

(d) for each **DC Converter** at a **DC Converter Station** or **DC Converter** connecting a **Power Park Module**

DC Converter type (e.g. current/voltage sourced)
Rated MW per pole for import and export
Number of poles and pole arrangement
Rated DC voltage/pole (kV)
Return path arrangement
Remote AC connection arrangement

(e) for each type of **Power Park Unit** in a **Power Park Module** not connected to the **Total System** by a **DC Converter**:

Rated MVA
Rated MW
Rated terminal voltage
Inertia constant, (MWsec/MVA)
Additionally, for **Power Park Units** that are squirrel-cage or doubly-fed induction generators driven by wind turbines:
Stator reactance.
Magnetising reactance.
Rotor resistance (at rated running)

Rotor reactance (at rated running)
The generator rotor speed range (minimum and maximum speeds in RPM) (for doubly-fed induction generators only)
Converter MVA rating (for doubly-fed induction generators only)

For a **Power Park Unit** consisting of a synchronous machine in combination with a back-to-back **DC Converter,** or for a **Power Park Unit** not driven by a wind turbine, the data to be supplied shall be agreed with **NGC** in accordance with PC.A.7.

This information should only be given in the data supplied with the application for a **CUSC Contract** (if appropriate for any variation), as the case may be.

PC.A.3.4 General **Generating Unit** **Power Park Module** and **DC Converter** Data

PC.A.3.4.1 The point of connection to the **GB Transmission System** or the **Total System**, if other than to the **GB Transmission System**, in terms of geographical and electrical location and system voltage is also required.

PC.A.3.4.2 (a) Type of **Generating Unit** (ie **Synchronous Generating Unit, Non-synchronous Generating Unit** , **DC Converter** or **Power Park Module).**

(~~a~~b) In the case of a **Synchronous Generating Unit** ~~D~~details of the **Exciter** category, for example whether it is a rotating **Exciter** or a static **Exciter** or in the case of a **Non-Synchronous Generating Unit** the voltage control system**.**

(~~b~~c) Whether a **Power System Stabiliser** is fitted.

PC.A.4 **DEMAND** AND **ACTIVE ENERGY** DATA

PC.A.4.1 Introduction

PC.A.4.1.1 Each **User** directly connected to the **GB Transmission System** with **Demand** shall provide **NGC** with the **Demand** data, historic, current and forecast, as specified in PC.A.4.2, PC.A.4.3 and PC.A.4.5. Paragraphs PC.A.4.1.2 and PC.A.4.1.3 apply equally to **Active Energy** requirements as to **Demand** unless the context otherwise requires.

PC.A.4.1.2 Data will need to be supplied by:

(a) each **Network Operator**, in relation to **Demand** and **Active Energy** requirements on its **User System**;

(b) each **Non-Embedded Customer** (including **Pumped Storage Generators** with respect to Pumping **Demand**) in relation to its **Demand** and **Active Energy** requirements.

(c) each **DC Converter Station** owner, in relation to **Demand** and **Active Energy** transferred (imported) to its **DC Converter Station**.

Demand of **Power Stations** directly connected to the **GB Transmission System** is to be supplied by the **Generator** under PC.A.5.2.

PC.A.4.1.3 References in this **PC** to data being supplied on a half hourly basis refer to it being supplied for each period of 30 minutes ending on the hour or half-hour in each hour.

PC.A.4.2 **Demand** (**Active Power**) and **Active Energy** Data

……..

PC.A.4.2.4 All forecast **Demand** (**Active Power**) and **Active Energy** specified in PC.A.4.2.1 and PC.A.4.2.3 shall:

(a) in the case of PC.A.4.2.1(a), (b) and (c), be such that the profiles comprise average **Active Power** levels in 'MW' for each time marked half hour throughout the day;

(b) in the case of PC.A.4.2.1(a), (b) and (c), be that remaining after any deductions reasonably considered appropriate by the **User** to take account of the output profile of all **Embedded Small Power Stations** and **Embedded Medium Power Stations** and **Customer Generating Plant** and imports across **Embedded External Interconnections** including imports across **Embedded** installations of direct current converters which do not form a **DC Converter Station** and

Embedded DC Converter Stations with a **Registered Capacity** of less than 100MW;

(c) in the case of PC.A.4.2.1(a) and (b), be based on **Annual ACS Conditions** and in the case of PC.A.4.2.1(c) and the details of the annual **Active Energy** required under PC.A.4.2.3 be based on **Average Conditions**.

PC.A.4.3 **Connection Point Demand (Active and Reactive Power)**

…….

PC.A.4.3.2 All forecast **Demand** specified in PC.A.4.3.1 shall:

(a) be that remaining after any deductions reasonably considered appropriate by the **User** to take account of the output of all **Embedded Small Power Stations** and **Embedded Medium Power Stations** and **Customer Generating Plant** and imports across **Embedded External Interconnections** , including **Embedded** installations of direct current converters which do not form a **DC Converter Station** and **Embedded DC Converter Stations** and such deductions should be separately stated;

(b) include any **User's System** series reactive losses but exclude any reactive compensation equipment specified in PC.A.2.4 and exclude any network susceptance specified in PC.A.2.3;

(c) in the case of PC.A.4.3.1(a) and (b) be based on **Annual ACS Conditions** and in the case of PC.A.4.3.1(c) be based on **Average Conditions**.

………

PART 2

DETAILED PLANNING DATA

PC.A.5 **GENERATING UNIT, POWER PARK MODULE AND DC CONVERTER** DATA

PC.A.5.1 Introduction

Directly Connected

PC.A.5.1.1 Each **Generator**, with existing or proposed **Power Stations** directly connected, or to be directly connected, to the **GB Transmission System**, shall provide **NGC** with data relating to that **Plant** and **Apparatus**, both current and forecast, as specified in PC.A.5.2 ~~and~~ PC.A.5.3 and PC.A.5.4 as applicable. Each **DC Converter Station** owner, with existing or proposed **DC Converter Stations** directly connected, or to be directly connected, to the **GB Transmission System**, shall provide **NGC** with data relating to that **Plant** and **Apparatus**, both current and forecast, as specified in PC.A.5.2 and PC.A.5.4.

Embedded

PC.A.5.1.2 Each **Generator**, with existing or proposed **Embedded Large Power Stations** and **Embedded Medium Power Stations** shall provide **NGC** with data relating to each of those **Large Power Stations** and/or **Medium Power Stations**, both current and forecast, as specified in PC.A.5.2, ~~and~~ PC.A.5.3 and PC.A.5.4 as applicable. Each **DC Converter Station** owner, with existing or proposed **DC Converter Stations** shall provide **NGC** with data relating to each of those **DC Converter Stations**, both current and forecast, as specified in PC.A.5.2 and PC.A.5.4. However, no data need be supplied in relation to those **Embedded Medium Power Stations** if they are connected at a voltage level below the voltage level of the **Subtransmission System** except in connection with an application for, or under a, **CUSC Contract** or unless specifically requested by **NGC** under PC.A.5.1.4.

………

PC.A.5.2 **Demand**

PC.A.5.2.1 For each **Generating Unit** which has an associated **Unit Transformer**, the value of the **Demand** supplied through this **Unit Transformer** when the **Generating Unit** is at **Rated MW** output is to be provided.

PC.A.5.2.2 Where the **Power Station** or **DC Converter Station** has associated **Demand** additional to the unit-supplied **Demand** of PC.A.5.2.1 which is supplied from either the **GB Transmission System** or the **Generator's User System** the **Generator** or **DC Converter Station** owner shall supply forecasts for each **Power Station** or **DC Converter Station** of:

a) the maximum **Demand** that, in the **User's** opinion, could reasonably be imposed on the **GB Transmission System** or the **Generator's User System** as appropriate;

b) the **Demand** at the time of the peak **GB Transmission System Demand**;

c) the **Demand** at the time of minimum **GB Transmission System Demand.**

……..

PC.A.5.3 **Synchronous Generating Unit**~~Machine~~ and Associated Control System Data

PC.A.5.3.1 The data submitted below are not intended to constrain any **Ancillary Services Agreement**

PC.A.5.3.2 The following <u>Synchronous</u> **Generating Unit** and **Power Station** data should be supplied:

(a) <u>Synchronous **Generating Unit** Parameters</u>

Rated terminal volts (kV)
* Rated MVA
* **Rated MW**
* Minimum Generation MW
* Short circuit ratio

Direct axis synchronous reactance
* Direct axis transient reactance

Direct axis sub-transient reactance
Direct axis short-circuit transient time constant.
Direct axis short-circuit sub-transient time constant.
Quadrature axis synchronous reactance
Quadrature axis sub-transient reactance
Quadrature axis short-circuit sub-transient time constant.
Stator time constant
Stator leakage reactance
Armature winding direct-current resistance.

<u>Note:</u> The above data item relating to armature winding direct-current resistance need only be supplied by **Generators** with respect to **Generating Units** commissioned after 1st March 1996 and in cases where, for whatever reason, the **Generator** is aware of the value of the relevant parameter.

* Turbogenerator inertia constant (MWsec/MVA)

Rated field current (amps) at **Rated MW** and Mvar output and at rated terminal voltage.

Field current (amps) open circuit saturation curve for **Generating Unit** terminal voltages ranging from 50% to 120% of rated value in 10% steps as derived from appropriate manufacturers test certificates.

(b) <u>Parameters for **Generating Unit** Step-up Transformers</u>

* Rated MVA

Voltage ratio
* Positive sequence reactance (at max, min, & nominal tap)

Positive sequence resistance (at max, min, & nominal tap)
Zero phase sequence reactance
Tap changer range
Tap changer step size
Tap changer type: on load or off circuit

(c) <u>Excitation Control System parameters</u>

Note: The data items requested under Option 1 below may continue to be provided by **Generators** in relation to **Generating Units** on the **System** at 09 January 1995 (in this paragraph, the "relevant date") or they may provide the new data items set out under Option 2. **Generators** must supply the data as set out under Option 2 (and not those under Option 1) for **Generating Unit** excitation control systems commissioned after the relevant date, those **Generating Unit** excitation control systems recommissioned for any reason such as refurbishment after the relevant date and **Generating Unit** excitation control systems where, as a result of testing or other process, the **Generator** is aware of the data items listed under Option 2 in relation to that **Generating Unit**.

Option 1

DC gain of **Excitation Loop**
Rated field voltage
Maximum field voltage
Minimum field voltage
Maximum rate of change of field voltage (rising)
Maximum rate of change of field voltage (falling)
Details of **Excitation Loop** described in block diagram form showing transfer functions of individual elements.
Dynamic characteristics of **Over-excitation Limiter**.
Dynamic characteristics of **Under-excitation Limiter**

Option 2

Excitation System Nominal Response
Rated Field Voltage
No-Load Field Voltage
Excitation System On-Load Positive Ceiling Voltage
Excitation System No-Load Positive Ceiling Voltage
Excitation System No-Load Negative Ceiling Voltage

Details of **Excitation System** (including **PSS** if fitted) described in block diagram form showing transfer functions of individual elements.

Details of **Over-excitation Limiter** described in block diagram form showing transfer functions of individual elements.

Details of **Under-excitation Limiter** described in block diagram form showing transfer functions of individual elements.

(d) Governor Parameters

Incremental **Droop** values (in %) are required for each **Generating Unit** at six MW loading points (MLP1 to MLP6) as detailed in PC.A.5.~~4~~5.1 (this data item needs only be provided for **Large Power Stations**)

Note: The data items requested under Option 1 below may continue to be provided by **Generators** in relation to **Generating Units** on the **System** at 09 January 1995 (in this paragraph, the "relevant date") or they may provide the new data items set out under Option 2. **Generators** must supply the data as set out under Option 2 (and not those under Option 1) for **Generating Unit** governor control systems commissioned after the relevant date, those **Generating Unit** governor control systems recommissioned for any reason such as refurbishment after the relevant date and **Generating Unit** governor control systems where, as a result of testing or other process, the **Generator** is aware of the data items listed under Option 2 in relation to that **Generating Unit**.

Option 1

(i) Governor Parameters (for Reheat **Steam Units**)

HP governor average gain MW/Hz
Speeder motor setting range
HP governor valve time constant
HP governor valve opening limits
HP governor valve rate limits
Reheater time constant (**Active Energy** stored in reheater)

IP governor average gain MW/Hz
IP governor setting range
IP governor valve time constant
IP governor valve opening limits
IP governor valve rate limits

Details of acceleration sensitive elements in HP & IP governor loop.
A governor block diagram showing transfer functions of individual elements.

(ii) Governor Parameters (for Non-Reheat **Steam Units** and **Gas Turbine Units**)

Governor average gain
Speeder motor setting range
Time constant of steam or fuel governor valve
Governor valve opening limits
Governor valve rate limits
Time constant of turbine
Governor block diagram

The following data items need only be supplied for Large Power Stations:-

(iii) Boiler & Steam Turbine Data

Boiler Time Constant (Stored **Active Energy**)
s
HP turbine response ratio:
proportion of **Primary Response**
%
arising from HP turbine.

HP turbine response ratio:
proportion of **High Frequency Response**
%
arising from HP turbine.

[End of Option 1]

Option 2

(i) Governor and associated prime mover Parameters - All **Generating Units**

Governor Block Diagram showing transfer function of individual elements including acceleration sensitive elements.
Governor Time Constant (in seconds)
Speeder Motor Setting Range (%)
Average Gain (MW/Hz)
Governor Deadband (this data item need only be provided for **Large Power Stations**)

- Maximum Setting	±Hz
- Normal Setting	±Hz
- Minimum Setting	±Hz

Where the **Generating Unit** governor does not have a selectable deadband facility, then the actual value of the deadband need only be provided

(ii) Governor and associated prime mover Parameters **- Steam Units**

HP Valve Time Constant (in seconds)
HP Valve Opening Limits (%)
HP Valve Opening Rate Limits (%/second)
HP Valve Closing Rate Limits (%/second)
HP Turbine Time Constant (in seconds)

IP Valve Time Constant (in seconds)
IP Valve Opening Limits (%)
IP Valve Opening Rate Limits (%/second)
IP Valve Closing Rate Limits (%/second)

IP Turbine Time Constant (in seconds)

LP Valve Time Constant (in seconds)
LP Valve Opening Limits (%)
LP Valve Opening Rate Limits (%/second)
LP Valve Closing Rate Limits (%/second)
LP Turbine Time Constant (in seconds)

Reheater Time Constant (in seconds)
Boiler Time Constant (in seconds)
HP Power Fraction (%)
IP Power Fraction (%)

(iii) Governor and associated prime mover Parameters - **Gas Turbine Units**

Inlet Guide Vane Time Constant (in seconds)
Inlet Guide Vane Opening Limits (%)
Inlet Guide Vane Opening Rate Limits (%/second)
Inlet Guide Vane Closing Rate Limits (%/second)
Fuel Valve Constant (in seconds)
Fuel Valve Opening Limits (%)
Fuel Valve Opening Rate Limits (%/second)
Fuel Valve Closing Rate Limits (%/second)

Waste Heat Recovery Boiler Time Constant (in seconds)

(iv) Governor and associated prime mover Parameters - Hydro Generating Units

Guide Vane Actuator Time Constant (in seconds)
Guide Vane Opening Limits (%)
Guide Vane Opening Rate Limits (%/second)
Guide Vane Closing Rate Limits (%/second)
Water Time Constant (in seconds)

[End of Option 2]

(e) Unit Control Options

The following data items need only be supplied with respect to **Large Power Stations**:

Maximum ~~d~~**Droop**	%
Normal ~~d~~**Droop**	%
Minimum ~~d~~**Droop**	%
Maximum **Frequency** deadband	±Hz
Normal **Frequency** deadband	±Hz
Minimum **Frequency** deadband	±Hz
Maximum output deadband	±MW
Normal output deadband	±MW

Minimum output deadband ±MW

Frequency settings between which Unit Load Controller ~~d~~**Droop** applies:

- Maximum Hz
- Normal Hz
- Minimum Hz

State if sustained response is normally selected.

(f) Plant Flexibility Performance

The following data items need only be supplied with respect to **Large Power Stations,** and should be provided with respect to each **Genset:**

Run-up rate to **Registered Capacity,**
Run-down rate from **Registered Capacity**,
Synchronising Generation,
Regulating range
Load rejection capability while still **Synchronised** and able to supply **Load.**

Data items marked with a hash (#) should be applicable to a **Genset** which has been **Shutdown** for 48 hours.

* Data items marked with an asterisk are already requested under part 1, PC.A.3.3.1, to facilitate an early assessment by **NGC** as to whether detailed stability studies will be required before an offer of terms for a **CUSC Contract** can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.

PC.A.5.4 **Non-Synchronous Generating Unit** and Associated Control System Data

PC.A.5.4.1 The data submitted below are not intended to constrain any **Ancillary Services Agreement**

PC.A.5.4.2 The following **Power Park Unit, Power Park Module** and **Power Station** data should be supplied in the case of a **Power Park Module** not connected to the **Total System** by a **DC Converter**:

(a) **Power Park Unit** model

A mathematical model of each type of **Power Park Unit** capable of representing its transient and dynamic behaviour under both small and large disturbance conditions. The model shall include non-linear effects and represent all equipment relevant to the dynamic performance of the **Power Park Unit** as agreed with **NGC**. The model shall be suitable for the study of balanced, root mean square, positive phase sequence time-domain behaviour, excluding the effects of electromagnetic transients, harmonic and sub-harmonic frequencies.

The model shall accurately represent the overall performance of the **Power Park Unit** over its entire operating range including that which is inherent to the **Power Park Unit** and that which is achieved by use of supplementary control systems providing either continuous or stepwise control. Model resolution should be sufficient to accurately represent **Power Park Unit** behaviour both in response to operation of transmission system protection and in the context of longer-term simulations.

The overall structure of the model shall include:

(i) any supplementary control signal modules not covered by (c), (d) and (e) below.

(ii) any blocking, deblocking and protective trip features that are part of the **Power Park Unit** (e.g. “crowbar”).

(iii) any other information required to model the **Power Park Unit** behaviour to meet the model functional requirement described above.

The model shall be submitted in the form of a transfer function block diagram and may be accompanied by dynamic and algebraic equations. This model shall display all the transfer functions and their parameter values, any non wind-up logic, signal limits and non-linearities.

The submitted **Power Park Unit** model shall have been validated and this shall be confirmed by the **Generator**. The validation shall be based on comparing the submitted model simulation results against measured test results. Validation evidence shall also be submitted and this shall include the simulation and measured test results. The latter shall include appropriate short-circuit tests.

(b) **Power Park Unit** parameters

* Rated MVA
* **Rated MW**
* Rated terminal voltage
* Inertia constant (MWsec/MVA) at synchronous speed

Additionally, for **Power Park Units** that are squirrel-cage or doubly-fed induction generators driven by wind turbines:

* Stator resistance
* Stator reactance
* Magnetising reactance.
* Rotor resistance.(at starting)
* Rotor resistance.(at rated running)
* Rotor reactance (at starting)
* Rotor reactance (at rated running)

Inertia constant (MWsec/MVA) of the wind turbine rotor
Inertia constant (MWsec/MVA) of the generator rotor
Shaft stiffness (Nm/electrical radian)

Additionally for doubly-fed induction generators only:
The generator rotor speed range (minimum and

maximum speeds in RPM)
The optimum generator rotor speed versus wind speed submitted in tabular format
Power converter rating (MVA)

The rotor power coefficient (C_p) versus tip speed ratio (λ) curves for a range of blade angles (where applicable) together with the corresponding values submitted in tabular format. The tip speed ratio (λ) is defined as $\Omega R/U$ where Ω is the angular velocity of the rotor, R is the radius of the wind turbine rotor and U is the wind speed.

The electrical power output versus generator rotor speed for a range of wind speeds over the entire operating range of the **Power Park Unit**, together with the corresponding values submitted in tabular format.

The blade angle versus wind speed curve together with the corresponding values submitted in tabular format.

The electrical power output versus wind speed over the entire operating range of the **Power Park Unit**, together with the corresponding values submitted in tabular format.

Transfer function block diagram, including parameters and description of the operation of the power electronic converter (where applicable).

For a **Power Park Unit** consisting of a synchronous machine in combination with a back to back **DC Converter**, or for a **Power Park Unit** not driven by a wind turbine, the data to be supplied shall be agreed with **NGC** in accordance with PC.A.7.

(c) Torque / speed and blade angle control systems and parameters

For the **Power Park Unit**, details of the torque / speed controller and blade angle controller in the case of a wind turbine and power limitation functions (where applicable) described in block diagram form showing transfer functions and parameters of individual elements.

(d) Voltage/**Reactive Power**/**Power Factor** control system parameters

For the **Power Park Unit** and **Power Park Module** details of voltage/**Reactive Power**/**Power Factor** controller (and **PSS** if fitted) described in block diagram form showing transfer functions and parameters of individual elements.

(e) **Frequency** control system parameters

For the **Power Park Unit** and **Power Park Module** details of the **Frequency** controller described in block diagram form showing transfer functions and parameters of individual elements.

(f) Protection

Details of settings for the following protection relays (to include): Under **Frequency**, over **Frequency**, under voltage, over voltage, rotor over current, stator over current, high wind speed shut down level.

(g) Complete **Power Park Unit** model, parameters and controls

An alternative to PC.A.5.4.2 (a), (b), (c), (d), (e) and (f), is the submission of a single complete model that consists of the full information required under PC.A.5.4.2 (a), (b), (c), (d), (e) and (f) provided that all the information required under PC.A.5.4.2 (a), (b), (c), (d), (e) and (f) individually is clearly identifiable.

(h) Harmonic and flicker parameters

When connecting a **Power Park Module**, it is necessary for **NGC** to evaluate the production of flicker and harmonics on **NGC** and **User's Systems**. At **NGC's** reasonable request, the **User** is required to submit the following data (as defined in IEC 61400-21 (2001)) for each **Power Park Unit**:-

Flicker coefficient for continuous operation.
Flicker step factor.
Number of switching operations in a 10 minute window.
Number of switching operations in a 2 hour window.
Voltage change factor.
Current Injection at each harmonic for each **Power Park Unit** and for each **Power Park Module**

* Data items marked with an asterisk are already requested under part 1, PC.A.3.3.1, to facilitate an early assessment by **NGC** as to whether detailed stability studies will be required before an offer of terms for a **CUSC Contract** can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.

PC.A.5.4.3 **DC Converter**

PC.A.5.4.3.1 For a **DC Converter** at a **DC Converter Station** or a **Power Park Module** connected to the **Total System** by a **DC Converter** the following information for each **DC Converter** and **DC Network** should be supplied:

(a) **DC Converter** parameters

* **Rated MW** per pole for transfer in each direction;

* **DC Converter** type (i.e. current or voltage source);
* Number of poles and pole arrangement;
* Rated DC voltage/pole (kV);
* Return path arrangement;

(b) **DC Converter** transformer parameters

Rated MVA
Nominal primary voltage (kV);
Nominal secondary (converter-side) voltage(s) (kV);
Winding and earthing arrangement;
Positive phase sequence reactance at minimum, maximum and nominal tap;
Positive phase sequence resistance at minimum, maximum and nominal tap;
Zero phase sequence reactance;
Tap-changer range in %;
number of tap-changer steps;

(c) **DC Network** parameters

Rated DC voltage per pole;
Rated DC current per pole;
Single line diagram of the complete **DC Network**;
Details of the complete **DC Network**, including resistance, inductance and capacitance of all DC cables and/or DC lines;
Details of any DC reactors (including DC reactor resistance), DC capacitors and/or DC-side filters that form part of the **DC Network**;

(d) AC filter reactive compensation equipment parameters

Note: The data provided pursuant to this paragraph must not include any contribution from reactive compensation plant owned by **NGC.**

Total number of AC filter banks.
Type of equipment (e.g. fixed or variable)
Single line diagram of filter arrangement and connections;
Reactive Power rating for each AC filter bank ,capacitor bank or operating range of each item of reactive compensation equipment, at rated voltage;
Performance chart showing **Reactive Power** capability of the **DC Converter,** as a function of MW transfer, with all filters and reactive compensation plant, belonging to the **DC Converter Station** working correctly.

Note: Details in PC.A.5.4.3.1 are required for each **DC Converter** connected to the **DC Network**, unless each is identical or where the data has already been submitted for an identical **DC Converter** at another **Connection Point**.

Note: For a **Power Park Module** connected to the **Grid Entry point** or (**User System Entry Point** if **Embedded**) by a **DC Converter** the equivalent inertia and fault infeed at the **Power Park Unit** should be given.

DC Converter control system models

PC.A.5.4.3.2 The following data is required by **NGC** to represent **DC Converters** and associated **DC Networks** in dynamic power system simulations, in which the AC power system is typically represented by a positive sequence equivalent. **DC Converters** are represented by simplified equations and are not modelled to switching device level.

(i) Static V_{DC}-I_{DC} (DC voltage - DC current) characteristics, for both the rectifier and inverter modes for a current source converter. Static V_{DC}-P_{DC} (DC voltage - DC power) characteristics, for both the rectifier and inverter modes for a voltage source converter. Transfer function block diagram including parameters representation of the control systems of each **DC Converter** and of the **DC Converter Station**, for both the rectifier and inverter modes. A suitable model would feature the **DC Converter** firing angle as the output variable.

(ii) Transfer function block diagram representation including parameters of the **DC Converter** transformer tap changer control systems, including time delays

(iii) Transfer function block diagram representation including parameters of AC filter and reactive compensation equipment control systems, including any time delays.

(iv) Transfer function block diagram representation including parameters of any **Frequency** and/or load control systems.

(v) Transfer function block diagram representation including parameters of any small signal modulation controls such as power oscillation damping controls or sub-synchronous oscillation damping controls, that have not been submitted as part of the above control system data

(vi) Transfer block diagram representation of the **Reactive Power** control at converter ends for a voltage source converter.

Plant Flexibility Performance

PC.A.5.4.3.3 The following information on plant flexibility and performance should be supplied:

(i) Nominal and maximum (emergency) loading rate with the **DC Converter** in rectifier mode.

(ii) Nominal and maximum (emergency) loading rate with the **DC Converter** in inverter mode.

(iii) Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.

(iv) Maximum recovery time, to 90% of pre-fault loading, following a transient **DC Network** fault.

PC.A.5.4.3.4 Harmonic Assessment Information

DC Converter owners shall provide such additional further information as required by **NGC** in order that compliance with CC.6.1.5 can be demonstrated.

* Data items marked with an asterisk are already requested under part 1, PC.A.3.3.1, to facilitate an early assessment by **NGC** as to whether detailed stability studies will be required before an offer of terms for a **CUSC Contract** can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.

PC.A.5.45 Response data for **Frequency** changes

The information detailed below is required to describe the actual frequency response capability profile as illustrated in Figure CC.A.3.1 of the **Connection Conditions,** and need only be provided for each **Genset** at a **Large Power Stations.**

In this **PC.A.5.45**, for a **CCGT Module** with more than one **Generating Unit**, the phrase **Minimum Generation** applies to the entire **CCGT Module** operating with all **Generating Units Synchronised** to the **System**. Similarly for a **Power Park Module** with more than one **Power Park Unit**, the phrase **Minimum Generation** applies to the entire **Power Park Module** operating with all **Power Park Units Synchronised** to the **System.**

PC.A.5.45.1 MW loading points at which data is required

Response values are required at six MW loading points (MLP1 to MLP6) for each **Genset**. **Primary** and **Secondary Response** values need not be provided for MW loading points which are below **Minimum Generation**. MLP1 to MLP6 must be provided to the nearest MW.

Prior to the **Genset** being first **Synchronised**, the MW loading points must take the following values :-

MLP1	**Designed Minimum Operating Level**
MLP2	**Minimum Generation**
MLP3	70% of **Registered Capacity**
MLP4	80% of **Registered Capacity**
MLP5	95% of **Registered Capacity**
MLP6	**Registered Capacity**

When data is provided after the **Genset** is first **Synchronised**, the MW loading points may take any value between **Designed Minimum Operating Level** and **Registered Capacity** but the value of the **Designed Minimum Operating Level** must still be provided if it does not form one of the MW loading points.

PC.A.5.~~4~~5.2 **Primary** and **Secondary Response** to **Frequency** fall

Primary and **Secondary Response** values for a -0.5Hz ramp are required at six MW loading points (MLP1 to MLP6) as detailed above

PC.A.5.~~4~~5.3 **High Frequency Response** to **Frequency** rise

High Frequency Response values for a +0.5Hz ramp are required at six MW loading points (MLP1 to MLP6) as detailed above.

PC.A.5.~~5~~6 **Mothballed Generating Unit** **Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter Station** and Alternative Fuel Information

Data identified under this section PC.A.5.5 must be submitted as required under PC.A.1.2 and at **NGC**'s reasonable request.

PC.A.5.~~5~~6.1 **Mothballed Generating Unit** Information

Generators and **DC Converter Station** owners must supply with respect to each **Mothballed Generating Unit** **Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter Station** the estimated MW output which could be returned to service within the following time periods from the time that a decision to return was made:

< 1 month;

1-2 months;

2-3 months;

3-6 months;

6-12 months; and

>12 months.

The return to service time should be determined in accordance with **Good Industry Practice** assuming normal working arrangements and normal plant procurement lead times. The MW output values should be the incremental values made available in each time period as further described in the **DRC**.

PC.A.5.~~5~~6.2 **Generators** and **DC Converter Station** owners must also notify **NGC** of any significant factors which may prevent the **Mothballed Generating Unit** **, Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter Station** achieving the estimated values provided under PC.A.5.~~5~~6.1 above, excluding factors relating to **Transmission Entry Capacity**.

PC.A.5.~~5~~6.3 Alternative Fuel Information

The following data items must be supplied with respect to each **Generating Unit** whose main fuel is gas.

For each alternative fuel type (if facility installed):

(a) Alternative fuel type e.g. oil distillate, alternative gas supply

(b) For the changeover from main to alternative fuel:

- Time to carry out off-line and on-line fuel changeover (minutes).
- Maximum output following off-line and on-line changeover (MW).
- Maximum output during on-line fuel changeover (MW).
- Maximum operating time at full load assuming typical and maximum possible stock levels (hours).
- Maximum rate of replacement of depleted stocks (MWh electrical/day) on the basis of **Good Industry Practice.**
- Is changeover to alternative fuel used in normal operating arrangements?
- Number of successful changeovers carried out in the last **NGC Financial Year** (choice of 0, 1-5, 6-10, 11-20, >20).

(c) For the changeover back to main fuel:

- Time to carry out off-line and on-line fuel changeover (minutes).
- Maximum output during on-line fuel changeover (MW).

PC.A.5.~~5~~6.4 **Generators** must also notify **NGC** of any significant factors and their effects which may prevent the use of alternative fuels achieving the estimated values provided under PC.A.5.~~5~~6.3 above (e.g. emissions limits, distilled water stocks etc.)

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PC.A.6.3 **User's Protection Data**

PC.A.6.3.1 **Protection**

The following information is required which relates only to **Protection** equipment which can trip or inter-trip or close any **Connection Point** circuit-breaker or any **Transmission** circuit-breaker. This information need only be supplied once, in accordance with the timing requirements set out in PC.A.1.4(b), and need not be supplied on a routine annual basis thereafter, although **NGC** should be notified if any of the information changes

(a) a full description, including estimated settings, for all relays and **Protection** systems installed or to be installed on the **User's System;**

(b) a full description of any auto-reclose facilities installed or to be installed on the **User's System**, including type and time delays;

(c) a full description, including estimated settings, for all relays and **Protection** systems or to be installed on the generator, generator transformer, **Station Transformer** and their associated connections;

(d) for **Generating Units** (other than **Power Park Units**) or **Power Park Modules** or **DC Converters** at a **DC Converter Station** having (or intended to have) a circuit breaker at the generator terminal voltage, clearance times for electrical faults within the **Generating Unit** (other than a **Power Park Unit**) or **Power Park Module** zone;

(e) the most probable fault clearance time for electrical faults on any part of the **User's System** directly connected to the **GB Transmission System.**

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PC.A.7 ADDITIONAL DATA FOR NEW TYPES OF **POWER STATIONS**, **DC CONVERTER STATIONS** AND CONFIGURATIONS

Notwithstanding the **Standard Planning Data** and **Detailed Planning Data** set out in this Appendix, as new types of configurations and operating arrangements of **Power Stations** and **DC Converter Stations** emerge in future, **NGC** may reasonably require additional data to represent correctly the performance of such **Plant** and **Apparatus** on the **System**, where the present data submissions would prove insufficient for the purpose of producing meaningful **System** studies for the relevant parties.

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Single Line Diagram

The diagrams below show ~~two~~ three examples of single line diagrams, showing the detail that should be incorporated in the diagram. The first example is for an **Network Operator** connection, the second for a **Generator** connection, the third for a **Power Park Module** electrically equivalent system.

……..

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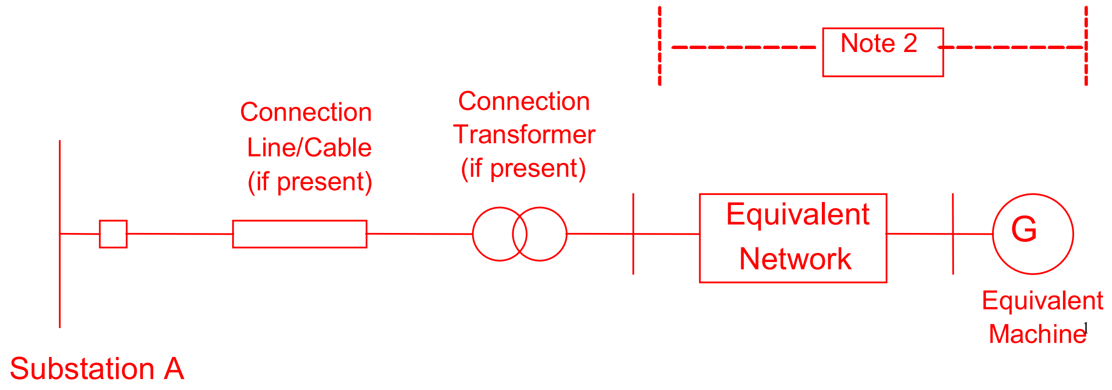
Power Park Module Single Line Diagram



Notes : 1) It is recommended that this consists of 'N' actual generators i.e. any equipment external to the generator terminals is considered part of the Equivalent Network

2) Where a Power Park Module consists of different Power Park Units, the equivalent machine and network can be repeated for each different unit

………

< End of **Planning Code (PC)** >

EXTRACTS FROM CONNECTION CONDITIONS

CC.1 INTRODUCTION

CC.1.1 The **Connection Conditions** ("**CC**") specify both the minimum technical, design and operational criteria which must be complied with by any **User** connected to or seeking connection with the **GB Transmission System** or **Generators** (other than in respect of **Small Power Stations**) or **DC Converter Station** owners connected to or seeking connection to a **User's System** which is located in **Great Britain**, and the minimum technical, design and operational criteria with which **NGC** will comply in relation to the part of the **GB Transmission System** at the **Connection Site** with **Users**.

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CC.3 SCOPE

CC.3.1 The **CC** applies to **NGC** and to **Users**, which in the **CC** means:

(a) **Generators** (other than those which only have **Embedded Small Power Stations**)

(b) **Network Operators**;

(c) **Non-Embedded Customers;** ~~and~~

(d) **DC Converter Station** owners; and

~~(d)~~(e) **BM Participants** and **Externally Interconnected System Operators** in respect of CC.6.5 only**.**

The above categories of **User** will become bound by the **CC** prior to them generating, distributing, supplying or consuming, as the case may be, and references to the various categories should, therefore, be taken as referring to them in that prospective role as well as to **Users** actually connected.

CC.4 PROCEDURE

CC.4.1 The **CUSC** contains provisions relating to the procedure for connection to the **GB Transmission System** or, in the case of **Embedded Power Stations** or **Embedded DC Converter Stations**, becoming operational and includes provisions relating to certain conditions to be complied with by **Users** prior to **NGC** notifying the **User** that it has the right to become operational.

CC.5. CONNECTION

CC.5.1 The provisions relating to connecting to the **GB Transmission System** (or to a **User's System** in the case of a connection of an **Embedded Large Power Station** or **Embedded Medium Power Station** or **Embedded DC Converter Station**) are contained in the **CUSC** and/or **CUSC Contract** (or in the relevant application form or offer for a **CUSC Contract**), and include provisions relating to both the submission of information and reports relating to compliance with the relevant **Connection Conditions** for that **User**, **Safety Rules**, commissioning programmes, **Operation Diagrams** and approval to connect. References in this **CC** to the "**Bilateral Agreement**" and/or "**Construction Agreement**" shall be deemed to include references to the application form or offer therefor.

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CC.5.3 As explained in the **Bilateral Agreement** and/or **Construction Agreement**, of the list:

(a) ~~in CC.5.2,~~ items CC.5.2 (c), (e), (g), (h), (k) and (m) need not be supplied in respect of **Embedded Power Stations** or **Embedded DC Converter Stations**,

(b) item CC.5.2(i) need not be supplied in respect of **Embedded Small Power Stations** and **Embedded Medium Power Stations** or **Embedded DC Converter Stations** with a **Registered Capacity** of less than 100MW, and

(c) items CC.5.2 (d) and (j) are only needed in the case where the **Embedded Power Station** or the **Embedded DC Converter Station** is within a **Connection Site** with another **User**.

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Voltage Waveform Quality

CC.6.1.5 All **Plant** and **Apparatus** connected to the **GB Transmission System**, and that part of the **GB Transmission System** at each **Connection Site**, should be capable of withstanding the following distortions of the voltage waveform in respect of harmonic content and phase unbalance:

(a) Harmonic Content

The **Electromagnetic Compatibility Levels** for harmonic distortion on the **GB Transmission System** from all sources under both **Planned Outage** and fault outage conditions, (unless abnormal conditions prevail) shall comply with the levels shown in the tables of Appendix A of **Engineering Recommendation** G5/4.

Engineering Recommendation G5/4 contains planning criteria which **NGC** will apply to the connection of non-linear ~~load~~ **Load** to the **GB Transmission System**, which may result in harmonic emission limits being specified for these ~~l~~**Loads** in the relevant **Bilateral Agreement**. The application of the planning criteria will take into account the position of existing and prospective **Users' Plant** and **Apparatus** in relation to harmonic emissions. **Users** must ensure that connection of distorting loads to their **User Systems** do not cause any harmonic emission limits specified in the **Bilateral Agreement**, or where no such limits are specified, the relevant planning levels specified in **Engineering Recommendation** G5/4 to be exceeded.

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CC.6.2.1 General Requirements

CC.6.2.1.1 (a) The design of connections between the **GB Transmission System** and:-

(i) any **Generating Unit** (other than a **CCGT Unit** or **Power Park Unit**)~~-~~, **DC Converter, Power Park Module** or **CCGT Module**, or

(ii) any **Network Operator's User System**, or

(iii) **Non-Embedded Customers** equipment;

will be consistent with the **Licence Standards**.

………

CC.6.2.2 Requirements at **Connection Points** that relate to **Generators** or **DC Converter Station** owners

CC.6.2.2.1 Not Used.

CC.6.2.2.2 **Generating Unit** and **Power Station Protection** Arrangements

CC.6.2.2.2.1 Minimum Requirements

Protection of **Generating Units** (other than **Power Park Units**), **DC Converters** or **Power Park Modules** and their connections to the **GB Transmission System** must meet the minimum requirements given below. These are necessary to reduce to a practical minimum the impact on the **GB Transmission System** of faults on circuits owned by **Generators** or **DC Converter Station** owners.

CC.6.2.2.2.2 Fault Clearance Times

(a) The fault clearance times for faults on the **Generator** or **DC Converter Station** owner's equipment directly connected to the **GB Transmission System** and for faults on the **GB Transmission System** directly connected to the **Generator** or **DC Converter Station** owner's equipment, from fault inception to the circuit breaker arc extinction, shall be set out in accordance with the **Bilateral Agreement**. The times specified in accordance with the **Bilateral Agreement** shall not be faster than:

(i) 80mS at 400kV
(ii) 100mS at 275kV
(iii) 120mS at 132kV and below

but this shall not prevent a **User** or **NGC** having faster fault clearance times.

Slower fault clearance times may be specified in accordance with the **Bilateral Agreement** for faults on the **GB Transmission System**. Slower fault clearance times for faults on the **Generator** or **DC Converter Station** owner's equipment may be agreed in accordance with the terms of the **Bilateral Agreement** but only if **System** requirements, in **NGC's** view, permit. The probability that the fault clearance times stated in accordance with the **Bilateral Agreement** will be exceeded by any given fault, must be less than 2%.

(b) For the event that the above fault clearance times are not met as a result of failure to operate on the **Main Protection System(s)** provided, the **Generators** or **DC Converter Station** owners shall provide **Back-Up Protection**. **NGC** will also provide **Back-Up Protection** and these **Back-Up Protections** will be co-ordinated so as to provide **Discrimination**.

On a **Generating Unit** (other than **Power Park Units**), **DC Converter** or **Power Park Module** connected to the **GB Transmission System** where only one **Main Protection** is provided to clear faults on the **HV** ~~**Generator**~~ **Connections** within the required fault clearance time, the **Back-Up Protection** provided by the **Generators** and **DC Converter Station** owners shall operate to give a fault clearance time of no slower than 300 ms at the minimum infeed for normal operation for faults on the **HV** ~~**Generator**~~ **Connections**. On **Generating Units** (other than **Power Park Units**), **DC Converters** or **Power Park Modules** connected to the **GB Transmission System** at 400 kV and 275 kV where two **Main Protections** are provided and on **Generating Units** (other than **Power Park Units**), **DC Converters** or **Power Park Modules** connected to the **GB Transmission System** at 132 kV and below, the **Back-Up Protection** shall operate to give a fault clearance time of no slower than 800 ms in England and Wales and 300 ms in Scotland at the minimum infeed for normal operation for faults on the **HV** ~~**Generator**~~ **Connections**.

Generators' and **DC Converter Station** owners**'** **Back-Up Protection** will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the **GB Transmission System** by breaker fail **Protection** at 400kV or 275kV or of a fault cleared by **Back-Up Protection** where the **Generator** or **DC Converter** is connected at 132kV and below. This will permit **Discrimination** between **Generator** or **DC Converter** **Back-Up Protection** and **Back-Up Protection** provided on the **GB Transmission System** and other **Users' Systems**.

(c) When the **Generating Unit** (other than a **Power Park Unit**), or the **DC Converter** or **Power Park Module** is connected to the **GB Transmission System** at 400kV or 275kV, and in Scotland also at 132kV, and a circuit breaker is provided by the **Generator**, or the **DC Converter Station** owner, or **NGC**, as the case may be, to interrupt fault current interchange with the **GB Transmission System**, or **Generator's System**, or **DC Converter Station** owner's **System**, as the case may be, circuit breaker fail **Protection** shall be provided by the **Generator**, or **DC Converter Station** owner, or **NGC**, as the case may be, on this circuit breaker. In the event, following operation of a **Protection** system, of a failure to interrupt fault current by these circuit-breakers within the **Fault Current Interruption Time,** the circuit breaker fail **Protection** is required to initiate tripping of all the necessary electrically adjacent circuit-breakers so as to interrupt the fault current within the next 200 ms.

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CC.6.2.2.3.2 Circuit-breaker fail **Protection**

The **Generator** or **DC Converter Station** owner will install circuit breaker fail **Protection** equipment in accordance with the requirements of the **Bilateral Agreement**. The **Generator** or **DC Converter Station** owner will also provide a back-trip signal in the event of loss of air from its pressurised head circuit breakers, during the **Generating Unit** (other than a **CCGT Unit** or **Power Park Unit**) or **CCGT Module** or **DC Converter** or **Power Park Module** run-up sequence, where these circuit breakers are installed.

……..

CC.6.2.2.3.5 Signals for Tariff Metering

Generators and **DC Converter Station** owners will install current and voltage transformers supplying all tariff meters at a voltage to be specified in, and in accordance with, the **Bilateral Agreement**.

CC.6.2.2.4 Work on **Protection** Equipment

No busbar **Protection**, mesh corner **Protection**, circuit-breaker fail **Protection** relays, AC or DC wiring (other than power supplies or DC tripping associated with the **Generating Unit**, **DC Converter** or **Power Park Module** itself) may be worked upon or altered by the **Generator** or **DC Converter Station** owner personnel in the absence of a representative of **NGC** or in Scotland, a representative of **NGC**, or written authority from **NGC** to perform such work or alterations in the absence of a representative of **NGC**.

………

CC.6.3 GENERAL **GENERATING UNIT**, **POWER PARK MODULE** AND **DC CONVERTER** REQUIREMENTS

CC.6.3.1 This section sets out the technical and design criteria and performance requirements for **Generating Units**, **DC Converters** and **Power Park Modules** (whether directly connected to the **GB Transmission System** or **Embedded**) which each **Generator** or **DC Converter Station** owner must ensure are complied with in relation to its **Generating Units**, **DC Converters** and **Power Park Modules** but does not apply to **Small Power Stations** or individually to **Power Park Units**~~, and in England and Wales, hydro units and renewable energy plant not designed for~~ ~~**Frequency** and voltage control~~. References to **Generating Units**, **DC Converters** and **Power Park Modules** in this CC.6.3 should be read accordingly.

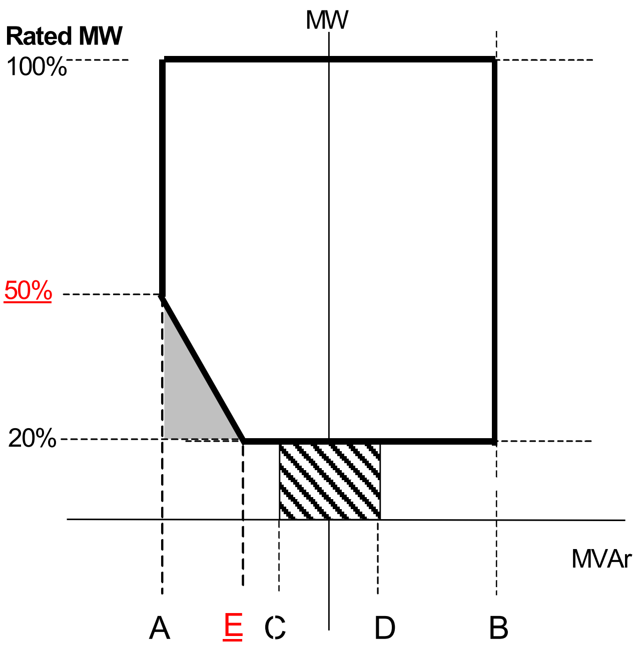
Plant Performance Requirements

CC.6.3.2 (a) All **Synchronous** **Generating Units** must be capable of supplying ~~rated~~ **Rated** ~~power output (~~**MW**~~)~~ at any point between the limits 0.85 ~~power~~ **Power** ~~factor~~ **Factor** lagging and 0.95 ~~power~~ **Power** ~~f~~**Factor** leading at the **Synchronous** **Generating Unit** terminals. The short circuit ratio of **Synchronous** **Generating Units** shall be not less than 0.5.

(b) Subject to paragraph (c) below, all **Non-Synchronous Generating Units, DC Converters** and **Power Park Modules** must be capable of maintaining zero transfer of **Reactive Power** at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) at all **Active Power** output levels under steady state voltage conditions. The steady state tolerance on **Reactive Power** transfer to and from the **GB Transmission System** expressed in MVAr shall be no greater than 5% of the **Rated MW.**

(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 (or **User System Entry Point** if **Embedded**). With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Lagging **Power Factor** will apply at all **Active**

Power output levels above 20% of the **Rated MW** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** will apply at all **Active Power** output levels above 50% of the **Rated MW** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure 1 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** down to 20% **Active Power** output is specified in the **Bilateral Agreement**. 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
Point E is equivalent (in MVAr) to: -12% of **Rated MW** output

Figure 1

(d) All **Non-Synchronous Generating Units** and **Power Park Modules** in Scotland with a **Completion Date** after 1 April 2005 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).

CC.6.3.3 Each **Generating Unit**~~-~~, **DC Converter**, **Power Park Module** and/or **CCGT Module** must be capable of

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure ~~1~~ 2 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%.

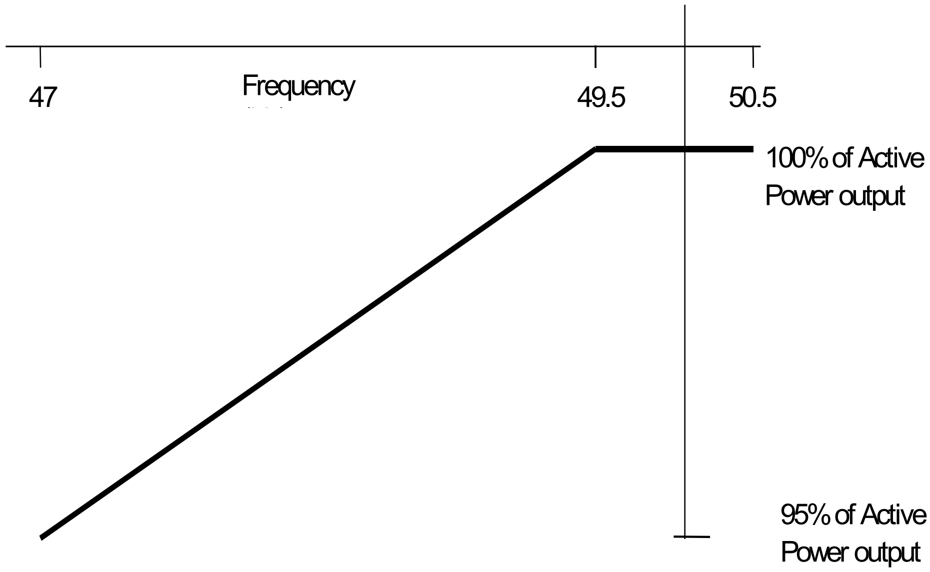


Figure 2~~1~~

(c) For the avoidance of doubt in the case of a **Generating Unit** or **Power Park Module** using an **Intermittent Power Source** where the mechanical power input will not be constant over time, the requirement is that the **Active Power** output shall be independent of **System Frequency** under (a) above and should not drop with **System Frequency** by greater than the amount specified in (b) above.

(d) A **DC Converter Station** must be capable of maintaining its **Active Power** input (i.e. when operating in a mode analogous to **Demand**) from the **GB Transmission System** (or **User System** in the case of an **Embedded DC Converter Station**) at a level not greater than the figure determined by the linear relationship shown in Figure 3 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47.8 Hz the **Active Power** input decreases by more than 60%.

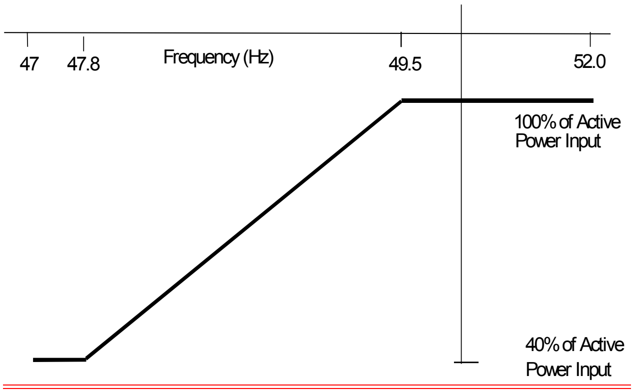


Figure 3

CC.6.3.4 At the **Grid Entry Point** the~~The~~ **Active Power** output under steady state conditions of any **Generating Unit**, **DC Converter** or **Power Park Module** directly connected to the **GB Transmission System** should not be affected by voltage changes in the normal operating range specified in paragraph CC.6.1.4 by more than the change in **Active Power** losses at reduced or increased voltage. 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, except for a **Power Park Module** or **Non-synchronous Generating Unit** if **Embedded** at 33kV and below (or directly connected to the **GB Transmission System** in England and Wales at 33kV and below) where the requirement shown in Figure 4 applies.

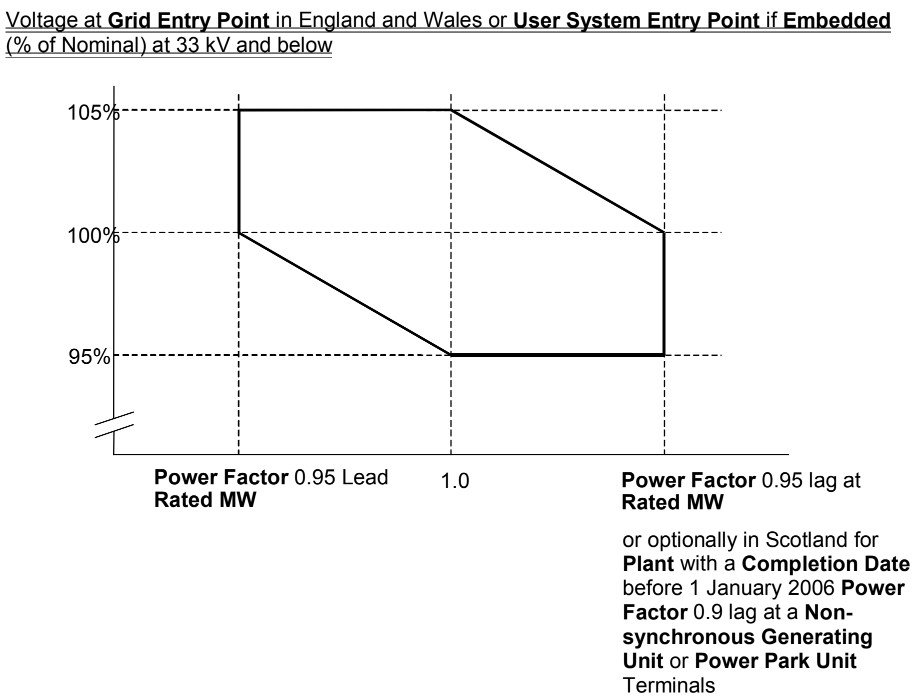


Figure 4

CC.6.3.5 It is an essential requirement that the **GB Transmission System** must incorporate a **Black Start Capability**. This will be achieved by agreeing a **Black Start**

Capability at a number of strategically located **Power Stations**. For each **Power Station NGC** will state in the **Bilateral Agreement** whether or not a **Black Start Capability** is required.

Control Arrangements

CC.6.3.6 ~~Each **Generating Unit** must be capable of contributing to **Frequency** and voltage control by continuous modulation of **Active Power** and **Reactive Power** supplied to the **GB Transmission System** or the **User System** in which it is **Embedded**.~~

(a) Each:

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

(ii) **DC Converter** with a **Completion Date** on or after 1 April 2005; or,

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

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

(ii) **DC Converter** (with a **Completion Date** on or after 1 April 2005 excluding current source technologies); or

(iii) **Power Park Module** in 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**.

CC.6.3.7 (a) Each **Generating Unit**, **DC Converter** or **Power Park Module** (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 (which may include a manufacturer specification);

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:

(i) Where a **Generating Unit , 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 CC.6.1.3. ;

(ii) the **Frequency** control device (or speed governor) must be capable of being set so that it operates with an overall speed ~~d~~**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 fulfil 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 **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 **F**~~f~~**requency** 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 1 April 2005 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** in operation in England and Wales with a **Completion Date** on or after 1 January 2006 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) ~~-~~**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 1 April 2005; or

(iii) ~~(iii)~~ **Power Park Modules** in England and Wales with a **Completion Date** before 1 January 2006 for whom only the requirements of **Limited Frequency Sensitive Mode** (BC.3.5.2) operation shall apply; or

(iv) ~~(iv)~~ **Power Park Modules** in operation in Scotland before 1 January 2006 for whom only the requirements of **Limited Frequency Sensitive Mode** (BC.3.5.2) operation shall apply; or

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

CC.6.3.8 (a) A continuously-acting automatic excitation control system is required to provide constant terminal voltage control of the **Synchronous Generating Unit** without instability over the entire operating range of the **Generating Unit**.

(b)~~–~~ The requirements for excitation control facilities, including ~~p~~**Power** ~~s~~**System** ~~s~~**Stabilisers**, where in **NGC's** view these are necessary for system reasons, will be specified in the **Bilateral Agreement**. Reference is made to on-load commissioning witnessed by **NGC** in BC2.11.2.

(c) In the case of a **Non-synchronous Generating Unit, DC Converter** or **Power Park Module** a continuously-acting automatic control system is required to provide control of the voltage (or zero transfer of **Reactive Power** as applicable to CC.6.3.2) at the **Grid Entry Point** or **User System Entry Point** without instability over the entire operating range of the **Non-Synchronous Generating Unit, DC Converter** or **Power Park Module**. In the case of a **Power Park Module** in Scotland, voltage control may be at the **Power Park Unit** terminals, an appropriate intermediate busbar or the **Connection Point** as specified in the **Bilateral Agreement**. The automatic control system shall be designed to ensure a smooth transition between the shaded area bound by CD and the non shaded area bound by AB in Figure 1 of CC6.3.2 (c). The performance requirements for this automatic control system will be specified in the **Bilateral Agreement**.

(~~b~~d) In particular, other control facilities, including constant **Reactive Power** output control modes and constant ~~p~~**Power** ~~f~~**Factor** control modes (but excluding VAR limiters) are not required. However, if present in the excitation or voltage control system they will be disabled unless recorded in the **Bilateral Agreement**. Operation of such control facilities will be in accordance with the provisions contained in **BC2.**

Steady state **Load** Inaccuracies

CC.6.3.9 The standard deviation of **Load** error at steady state **Load** over a 30 minute period must not exceed 2.5 per cent of a **Genset's Registered Capacity.** Where a **Genset** is instructed to **Frequency** sensitive operation, allowance will be made in determining whether there has been an error according to the governor droop characteristic registered under the **PC**.

For the avoidance of doubt in the case of a **Power Park Module** allowance will be made for the full variation of mechanical power output.

Negative Phase Sequence Loadings

CC.6.3.10 In addition to meeting the conditions specified in CC.6.1.5(b), each **Synchronous Generating Unit** 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** or **User System** in which it is **Embedded**.

Neutral **Earthing**

CC.6.3.11 At nominal **System** voltages of 132kV and above the higher voltage windings of a transformer of a **Generating Unit, DC Converter** or **Power Park Module** must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the **Earth Fault Factor** requirement of paragraph CC.6.2.1.1 (b) will be met on the **GB Transmission System** at nominal **System** voltages of 132kV and above.

Frequency Sensitive Relays

CC.6.3.12 As stated in CC.6.1.3, the **System Frequency** could rise to 52Hz or fall to 47Hz. Each **Generating Unit, DC Converter, Power Park Module** or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in CC.6.1.3 unless **NGC** has agreed to any **Frequency**-level relays and/or rate-of-change-of-**Frequency** relays which will trip such **Generating**

Unit , DC Converter, Power Park Module and any constituent element within this **Frequency** range, under the **Bilateral Agreement**.

CC.6.3.13 **Generators** and **DC Converter Station** owners will be responsible for protecting all their **Generating Units, DC Converters** or **Power Park Modules** against damage should **Frequency** excursions outside the range 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the **Generator** or **DC Converter Station** owner to decide whether to disconnect his **Apparatus** for reasons of safety of **Apparatus**, **Plant** and/or personnel.

CC.6.3.14 It may be agreed in the **Bilateral Agreement** that a **Genset** shall have a **Fast-Start Capability**. Such **Gensets** may be used for **Operating Reserve** and their **Start-Up** may be initiated by **Frequency**-level relays with settings in the range 49Hz to 50Hz as specified pursuant to **OC2**.

CC.6.3.15 Fault Ride Through

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

(i) Each **Generating Unit, DC Converter,** or **Power Park Module** and any constituent **Power Park Unit** 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 **Power Park Unit**, 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).

(ii) Each **Generating Unit** or **Power Park Module** 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 voltage at the **Grid Entry Point** ~~**Supergrid Voltage**~~ to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), **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 **Power Park Unit**.

(iii) 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 **Power Park Unit**, each with a **Completion Date** on or after the 1 April 2005 shall:

(i) remain transiently stable and connected to the **System** without tripping of any **Generating Unit** or **Power Park Module** and / or any constituent **Power Park Unit**, 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,

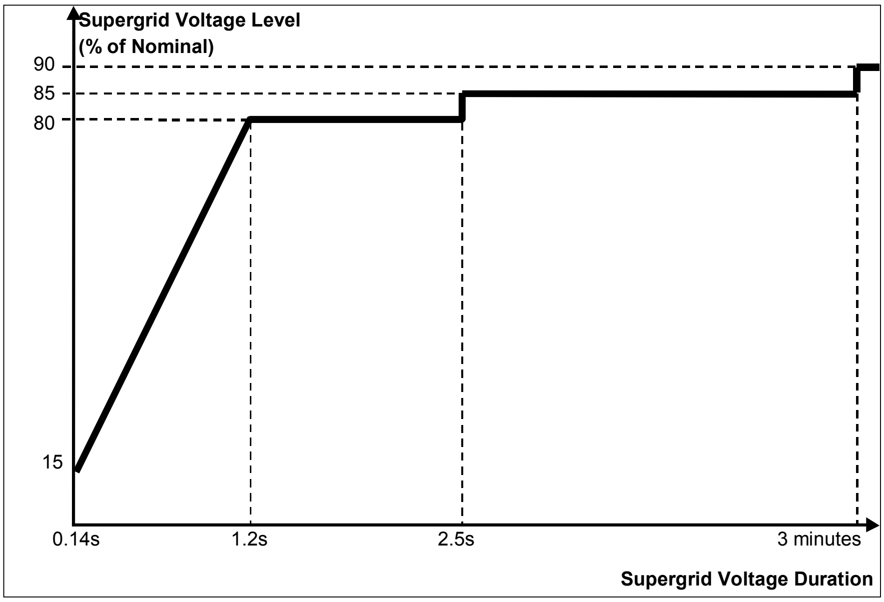


Figure 5

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

(iii) 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** 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

(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**.

(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 **Power Park Unit** 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**.

(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.

(iv) To avoid unwanted island operation, **Non-Synchronous Generating Units** in Scotland or **Power Park Modules** in Scotland shall be tripped for the following conditions:-

(1) Frequency above 52Hz for more than 2 seconds
(2) Frequency below 47Hz for more than 2 seconds
(3) Voltage as measured at the **Connection Point** or **User System Entry Point** below 80% for more than 2 seconds
(4) Voltage as measured at the **Connection Point** or **User System Entry Point** above 120% (115% for 275kV) for more than 1 second.

The times in sections (1) and (2) are maximum trip times. Shorter times may be used to protect the **Non-Synchronous Generating Units** or **Power Park Modules.**

Additional Damping Control Facilities for **DC Converters**

CC.6.3.16 (a) **DC Converter** owners must ensure that any of their **DC Converters** will not cause a sub-synchronous resonance problem on the **Total System**. Each **DC Converter** is required to be provided with sub-synchronous resonance damping control facilities.

(b) Where specified in the **Bilateral Agreement**, each **DC Converter** is required to be provided with power oscillation damping or any other identified additional control facilities.

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Control Telephony

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CC.6.5.4 Where **NGC** requires **Control Telephony**, **Users** are required to use the **Control Telephony** with **NGC** in respect of all **Connection Points** with the **GB Transmission System** and in respect of all **Embedded Large Power Stations** and

Embedded DC Converter Stations. **NGC** will install **Control Telephony** at the **User's** location where the **User's** telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the **Transmission Control Telephony**. Details of and relating to the **Control Telephony** required are contained in the **Bilateral Agreement**.

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Operational Metering

CC.6.5.6 (a) **NGC** shall provide system control and data acquisition (SCADA) outstation interface equipment. The **User** shall provide such voltage, current, **Frequency**, **Active Power** and **Reactive Power** measurement outputs and plant status indications and alarms to the **Transmission** SCADA outstation interface equipment as required by **NGC** in accordance with the terms of the **Bilateral Agreement**. ~~In addition, in Scotland, in the case of **Novel Units** utilising wind energy, anemometer readings would be required for any turbine or **Cluster** of turbines with a total **Registered Capacity** of 5MW and greater. In the case of a **Cluster** of wind turbines with a total **Registered Capacity** of 5MW or greater a single anemometer would suffice.~~

(b) For the avoidance of doubt, for **Active Power** and **Reactive Power** measurements, circuit breaker and disconnector status indications from:

(i) **CCGT Modules** at **Large Power Stations**, the outputs and status indications must each be provided to **NGC** on an individual **CCGT Unit** basis. In addition, where identified in the **Bilateral Agreement, Active Power** and **Reactive Power** measurements from **Unit Transformers** and/or **Station Transformers** must be provided.

(ii) **DC Converters** at **DC Converter Stations**, the outputs and status indications must each be provided to **NGC** on an individual **DC Converter** basis. In addition, where identified in the **Bilateral Agreement, Active Power** and **Reactive Power** measurements from converter and/or station transformers must be provided.

(iii) **Power Park Modules** at **Embedded Large Power Stations** and at directly connected **Power Stations,** the outputs and status indications must each be provided to **NGC** on an individual **Power Park Module** basis. In addition, where identified in the **Bilateral Agreement, Active Power** and **Reactive Power** measurements from station transformers must be provided.

(c) For the avoidance of doubt, the requirements of CC.6.5.6(a) in the case of a **Cascade Hydro Scheme** will be provided for each **Generating Unit** forming part of that **Cascade Hydro Scheme**. In the case of **Embedded Generating Units** forming part of a **Cascade Hydro Scheme** the data may be provided by means other than a **NGC** SCADA outstation located at the **Power Station**, such as, with the agreement of the **Network Operator** in whose system such **Embedded Generating Unit** is located, from the **Network Operator's** SCADA system to **NGC**. Details of such arrangements will be contained in the relevant **Bilateral Agreements** between **NGC** and the **Generator** and the **Network Operator**.

(d) In the case of a **Power Park Module** an additional energy input signal (e.g. wind speed) may be specified in the **Bilateral Agreement** . The signal may be used to establish the level of energy input from the **Intermittent Power Source** for monitoring pursuant to CC.6.6.1 and **Ancillary Services** and will, in the case of a wind farm, be used to provide **NGC** with advanced warning of excess wind speed shutdown.

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Facsimile Machines

CC.6.5.9 Each **User** and **NGC** shall provide a facsimile machine or machines:-

(a) in the case of **Generators,** at the **Control Point** of each **Power Station** and at its **Trading Point**;

(b) in the case of **NGC** and **Network Operators**, at the **Control Centre(s);** and

(c) in the case of **Non-Embedded Customers** and **DC Converter Station** owners at the **Control Point**.

Each **User** shall notify, prior to connection to the **System** of the **User's Plant and Apparatus**, **NGC** of its or their telephone number or numbers, and will notify **NGC** of any changes. Prior to connection to the **System** of the **User's Plant** and **Apparatus NGC** shall notify each **User** of the telephone number or numbers of its facsimile machine or machines and will notify any changes.

CC.6.5.10 Busbar Voltage

NGC shall, subject as provided below, provide each **Generator** or **DC Converter Station** owner at each **Grid Entry Point** where one of its **Power Stations** or **DC Converter Stations** is connected with appropriate voltage signals to enable the **Generator** or **DC Converter Station** owner to obtain the necessary information to ~~synchronise~~ permit its **Gensets** or **DC Converters** to be **Synchronised** to the **GB Transmission System.** The term **"voltage signal"** shall mean in this context, a point of connection on (or wire or wires from) a relevant part of **Transmission Plant** and/or **Apparatus** at the **Grid Entry Point**, to which the **Generator** or **DC Converter Station** owner**,** with **NGC's** agreement (not to be unreasonably withheld) in relation to the **Plant** and/or **Apparatus** to be attached, will be able to attach its **Plant** and/or **Apparatus** (normally a wire or wires) in order to obtain measurement outputs in relation to the busbar.

CC.6.5.11 Bilingual Message Facilities

(a) A Bilingual Message Facility is the method by which the **User's Responsible Engineer/Operator,** the **Externally Interconnected System Operator** and **NGC Control Engineers** communicate clear and unambiguous information in two languages for the purposes of control of the **Total System** in both normal and emergency operating conditions.

(b) A Bilingual Message Facility, where required, will provide up to two hundred pre-defined messages with up to five hundred and sixty characters each. A maximum of one minute is allowed for the transmission to, and display of, the selected message at any destination. The standard messages must be capable of being displayed at any combination of locations and can originate from any of these locations. Messages displayed in the UK will be displayed in the English language.

(c) Detailed information on a Bilingual Message Facility and suitable equipment required for individual **User** applications will be provided by **NGC** upon request.

CC.6.6 **SYSTEM** MONITORING

CC.6.6.1 Monitoring equipment is provided on the **GB Transmission System** to enable **NGC** to monitor its power system dynamic performance conditions. Where this monitoring equipment requires voltage and current signals on the **Generating Unit** (other than **Power Park Unit**), **DC Converter** or **Power Park Module** circuit from the **User**, **NGC** will inform the **User** and they will be provided by the **User** with both the timing of the installation of the equipment for receiving such signals and its exact position being agreed (the **User's** agreement not to be unreasonably withheld) and the costs being dealt with, pursuant to the terms of the **Bilateral Agreement**.

CC.7 SITE RELATED CONDITIONS

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CC.7.9 **Generators** and **DC Converter Station** owners shall provide a **Control Point** in respect of each **Power Station** directly connected to the **GB Transmission System** and **Embedded Large Power Station** or **DC Converter Station**. The **Control Point** shall be continuously manned (except for **Embedded Power Stations** containing **Power Park Modules** in the **SHETL Transmission Area** which have a **Registered Capacity** less than 30MW where the **Control Point** shall be manned between the hours of 0800 and 1800 each day) to receive and act upon instructions pursuant to OC7 and BC2 at all times that **Generating Units** or **Power Park Modules** at the **Power Station** are generating or available to generate or **DC Converters** at the **DC Converter Station** are importing or exporting or available to do so.

CC.8 **ANCILLARY SERVICES**

CC.8.1 **System Ancillary Services**

The **CC** contain requirements for the capability for certain **Ancillary Services**, which are needed for **System** reasons ("**System Ancillary Services**"). There follows a list of these **System Ancillary Services**, together with the paragraph number of the **CC** (or other part of the **Grid Code**) in which the minimum capability is required or referred to. The list is divided into two categories: Part 1 lists the **System Ancillary Services** which **Generators** are obliged to provide and **DC Converter Station** owners are obliged to have the capability to supply, and Part 2 lists the **System Ancillary Services** which **Generators** will provide only if agreement to provide them is reached with **NGC**:

Part 1

(a) **Reactive Power** supplied (in accordance with CC.6.3.2) otherwise than by means of synchronous or static compensators (except in the case of a **Power Park Module** where synchronous or static compensators within the **Power Park Module** may be used to provide **Reactive Power**) ~~CC.6.3.2~~

(b) **Frequency** Control by means of **Frequency** sensitive generation - CC.6.3.7 and BC3.5.1

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APPENDIX 1

FORMAT, PRINCIPLES AND BASIC PROCEDURE TO BE USED IN THE PREPARATION OF **SITE RESPONSIBILITY SCHEDULES**

CC.A.1.1 PRINCIPLES

Types of Schedules

CC.A.1.1.1 At all **Complexes** the following **Site Responsibility Schedules** shall be drawn up using the relevant proforma attached or with such variations as may be agreed between **NGC** and **Users**, but in the absence of agreement the relevant proforma attached will be used:

(a) Schedule of **HV Apparatus**

(b) Schedule of **Plant**, **LV/MV Apparatus**, services and supplies;

(c) Schedule of telecommunications and measurements **Apparatus**.

Other than at **Generating Unit**, **DC Converter, Power Park Module** and **Power Station** locations, the schedules referred to in (b) and (c) may be combined.

CONNECTION CONDITIONS

APPENDIX 3

MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE AND OPERATING RANGE for new ~~Generating Units and/or CCGT Modules with a Completion Date after 1 January 2001 in England and Wales and 1 April 2005 in Scotland~~Power Stations and DC Converter Stations

CC.A.3.1 SCOPE

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

(a) ~~-~~each **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~~.~~,

(b) each **DC Converter** at a **DC Converter Station** which has a **Completion Date** on or after 1 April 2005.

(c) each **Power Park Module** in England and Wales with a **Completion Date** on or after 1 January 2006.

(d) each **Power Park Module** in operation in Scotland 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) **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.~~/or~~

(ii) **DC Converters** at a **DC Converter Station** which have a **Completion Date** before 1 April 2005.

(iii) **Power Park Modules** in England and Wales with a **Completion Date** before 1 January 2006.

(iv) **Power Park Modules** in operation in Scotland before 1 January 2006.

(v) **Power Park Modules** in Scotland with a **Completion Date** before 1 April 2005.

(vi) **Power Park Modules** in Scotland in **Power Stations** with a **Registered Capacity** less than 30MW.

(vii) ~~to~~ **Small Power Stations** or individually to **Power Park Units**.

~~-~~The functional definition provides appropriate performance criteria relating to the provision of ~~f~~**Frequency** control by means of ~~f~~**Frequency** sensitive generation in addition to the other requirements identified in CC.6.3.7.

In this Appendix 3 to the **CC**, for a **CCGT Module** or a **Power Park Module** with more than one **Generating Unit**, the phrase **Minimum Generation** applies to the entire **CCGT Module** or **Power Park Module** operating with all **Generating Units Synchronised** to the **System**.

The minimum ~~f~~**Frequency** response requirement profile is shown diagrammatically in Figure CC.A.3.1. The capability profile specifies the minimum required levels of **Primary Response**, **Secondary Response** and **High Frequency Response** throughout the normal plant operating range. The definitions of these ~~f~~**Frequency** response capabilities are illustrated diagrammatically in Figures CC.A.3.2 & CC.A.3.3.

CC.A.3.2 PLANT OPERATING RANGE

The upper limit of the operating range is the **Registered Capacity** of the **Generating Unit** or **CCGT Module** or **DC Converter** or **Power Park Module**.

The **Minimum Generation** level may be less than, but must not be more than, 65% of the **Registered Capacity**. Each **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** and/or **DC Converter** must be capable of operating satisfactorily down to the **Designed Minimum Operating Level** as dictated by **System** operating conditions, although it will not be instructed to below its **Minimum Generation** level. If a **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** is operating below **Minimum Generation** because of high **System Frequency**, it should recover adequately to its **Minimum Generation** level as the **System Frequency** returns to **Target Frequency** so that it can provide **Primary** and **Secondary Response** from **Minimum Generation** if the **System Frequency** continues to fall. For the avoidance of doubt, under normal operating conditions steady state operation below **Minimum Generation** is not expected. The **Designed Minimum Operating Level** must not be more than 55% of **Registered Capacity**.

In the event of a **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** load rejecting down to no less than its **Designed Minimum Operating Level** it should not trip as a result of automatic action as detailed in BC3.7. If the load rejection is to a level less than the **Designed Minimum Operating Level** then it is accepted that the condition might be so severe as to cause it to be disconnected from the **System**.

CC.A.3.3 MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE

Figure CC.A.3.1 shows the minimum ~~f~~**Frequency** response requirement profile diagrammatically for a 0.5 Hz change in **Frequency**. The percentage response capabilities and loading levels are defined on the basis of the **Registered Capacity** of the **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter**. Each **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** and/or **DC Converter** must be capable of operating in a manner to provide ~~f~~**Frequency** response at least to the solid boundaries shown in the figure. If the frequency response capability falls within the solid boundaries, the **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** is providing response below the minimum requirement which is not acceptable. Nothing in this appendix is intended to prevent a **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** from being designed to deliver a ~~f~~**Frequency** response in excess of the identified minimum requirement.

The ~~f~~**Frequency** response delivered for **Frequency** deviations of less than 0.5 Hz should be no less than a figure which is directly proportional to the minimum ~~f~~**Frequency** response requirement for a **Frequency** deviation of 0.5 Hz. For example, if the **Frequency** deviation is 0.2 Hz, the corresponding minimum ~~f~~**Frequency** response requirement is 40% of the level shown in Figure CC.A.3.1. The ~~f~~**Frequency** response delivered for **Frequency** deviations of more than 0.5 Hz should be no less than the response delivered for a **Frequency** deviation of 0.5 Hz.

Each **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** and/or **DC Converter** must be capable of providing some response, in keeping with its specific operational characteristics, when operating between 95% to 100% of **Registered Capacity** as illustrated by the dotted lines in Figure CC.A.3.1.

At the **Minimum Generation** level, each **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** and/or **DC Converter** is required to provide high and low ~~f~~**Frequency** response depending on the **System Frequency** conditions. Where the **Frequency** is high, the **Active Power** output is therefore expected to fall below the **Minimum Generation** level.

The **Designed Minimum Operating Level** is the output at which a **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** and/or **DC Converter** has no **High Frequency Response** capability. It may be less than, but must not be more than, 55% of the **Registered Capacity**. This implies that a **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** is not obliged to reduce its output to below this level unless the **Frequency** is at or above 50.5 Hz (cf BC3.7).

CC.A.3.4 TESTING OF FREQUENCY RESPONSE CAPABILITY

The response capabilities shown diagrammatically in Figure CC.A.3.1 are measured by taking the responses as obtained from some of the dynamic response tests specified by **NGC** and carried out by **Generators** and **DC Converter Station** owners for compliance purposes and to validate the content of **Ancillary Services Agreements** using an injection of a ~~f~~**Frequency** change to the plant control system (ie governor and load controller). The injected signal is a linear ramp from zero to 0.5 Hz ~~f~~**Frequency** change over a ten second period, and is sustained at 0.5 Hz ~~f~~**Frequency** change thereafter, as illustrated diagrammatically in figures CC.A.3.2 and CC.A.3.3.

The **Primary Response** capability (P) of a **Generating Unit** or a **CCGT Module** or a **Power Park Module** or a **DC Converter** is the minimum increase in **Active Power** output between 10 and 30 seconds after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2.

The **Secondary Response** capability (S) of a **Generating Unit** or a **CCGT Module** or a **Power Park Module** or a **DC Converter** is the minimum increase in **Active Power** output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2.

The **High Frequency Response** capability (H) of a **Generating Unit** or a **CCGT Module** or a **Power Park Module** or a **DC Converter** is the decrease in **Active Power** output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure CC.A.3.3.

CC.A.3.5 REPEATABILITY OF RESPONSE

When a **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** has responded to a significant **Frequency** disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than 20 minutes after the initial change of **System Frequency** arising from the **Frequency** disturbance.

Figure CC.A.3.1 - Minimum Frequency Response Requirement Profile

for a 0.5 Hz frequency change from Target Frequency

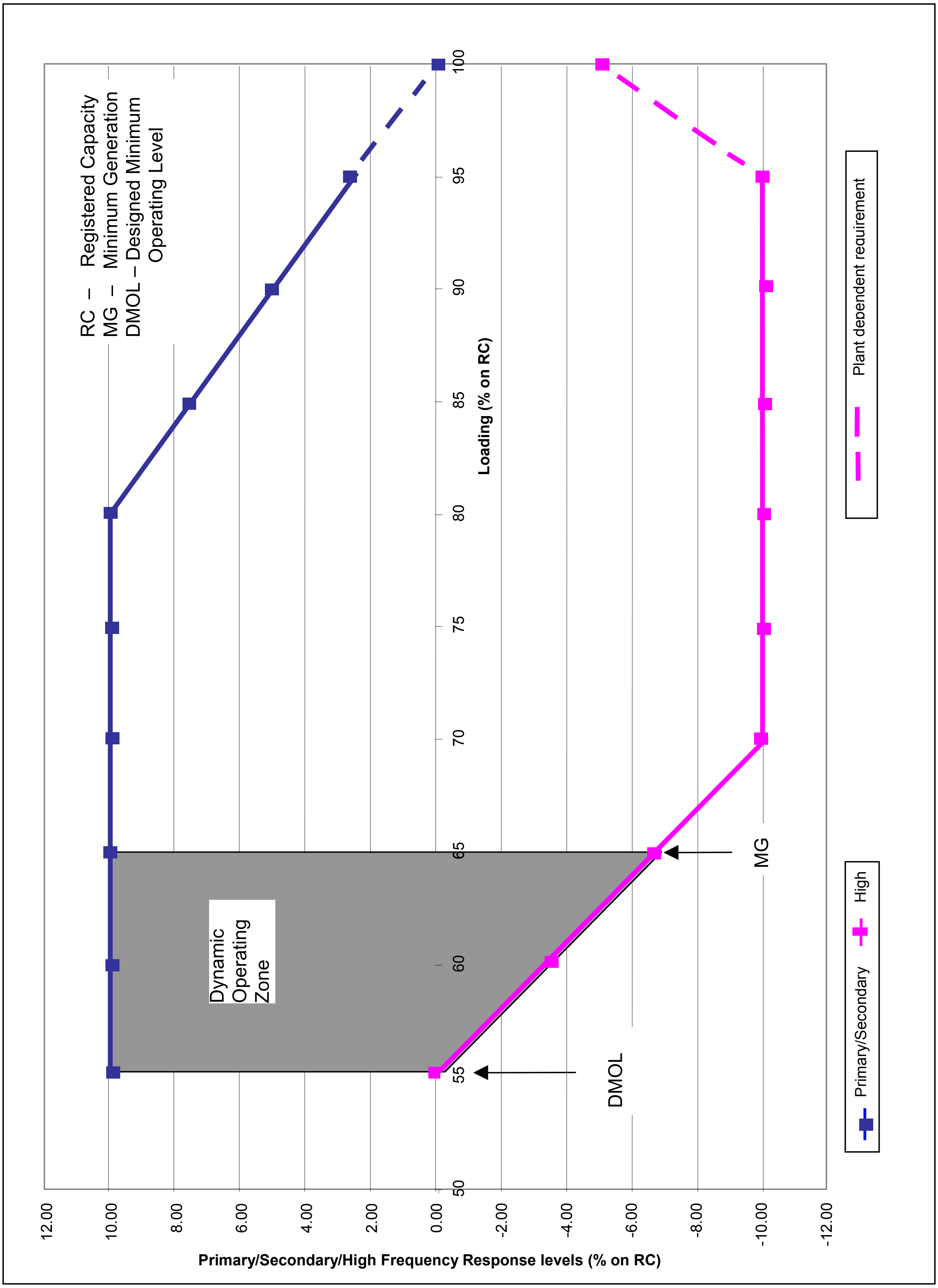


Figure CC.A.3.2 - Interpretation of Primary and Secondary Response Values

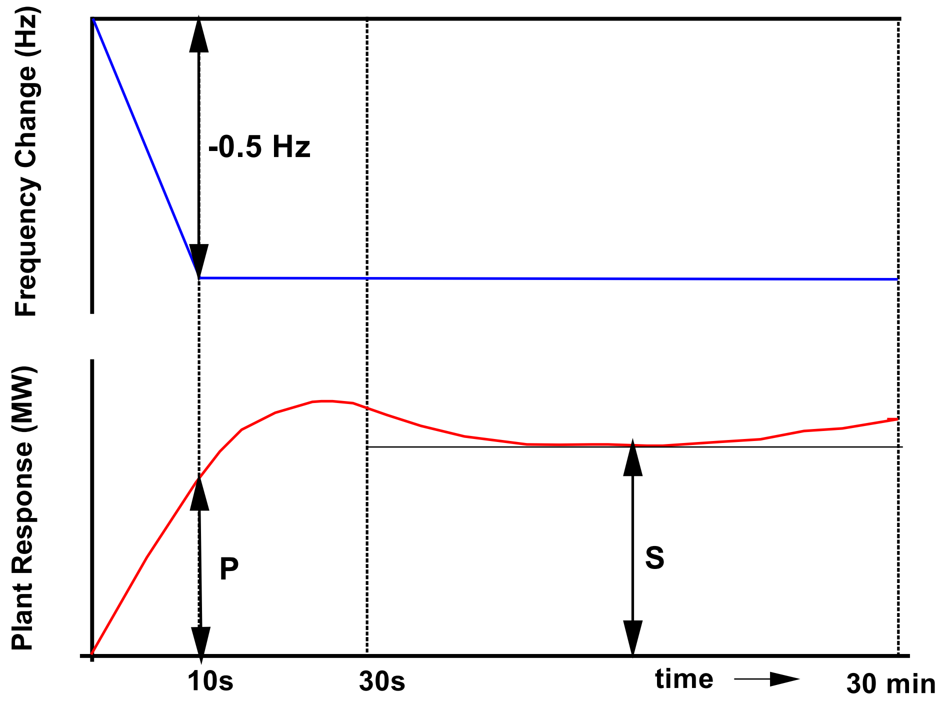
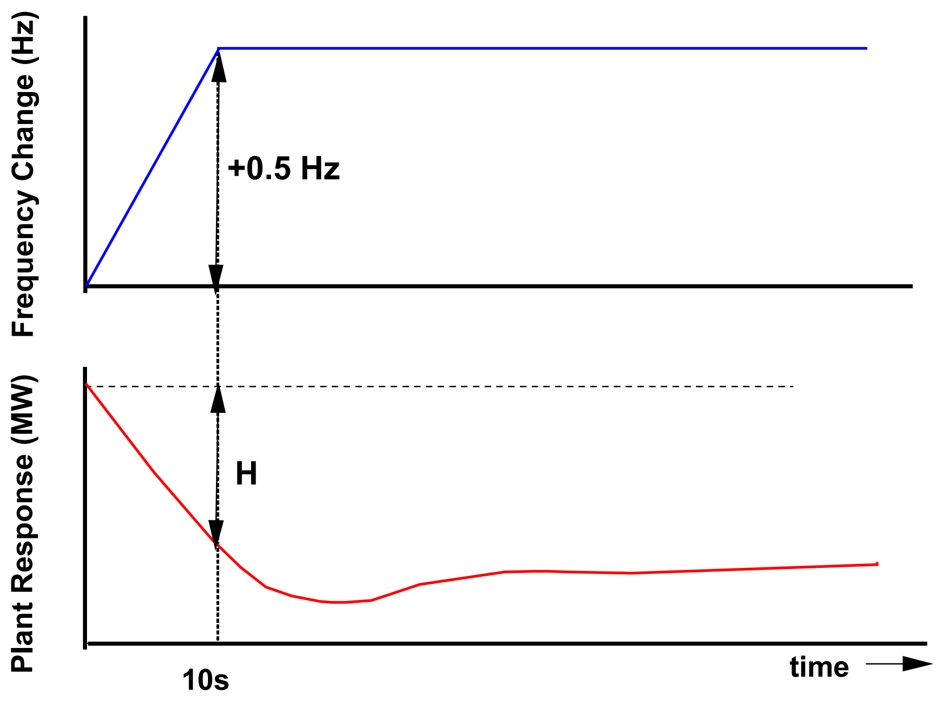


Figure CC.A.3.3 - Interpretation of High Frequency Response Values



APPENDIX 4

~~[Not Used]~~

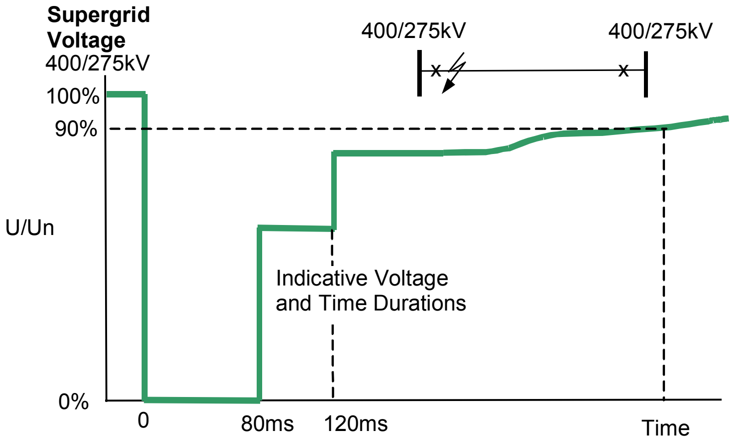
FAULT RIDE THROUGH REQUIREMENT FOR GENERATING UNITS, POWER PARK MODULES AND DC CONVERTERS

CC.A.4.1 SCOPE

The fault ride through requirement is defined in CC.6.3.15 (a), (b) and (c). This Appendix provides illustrations by way of examples only of CC.6.3.15 (a) (i) and further background and illustrations to CC.6.3.15 (b) (i) and is not intended to show all possible permutations.

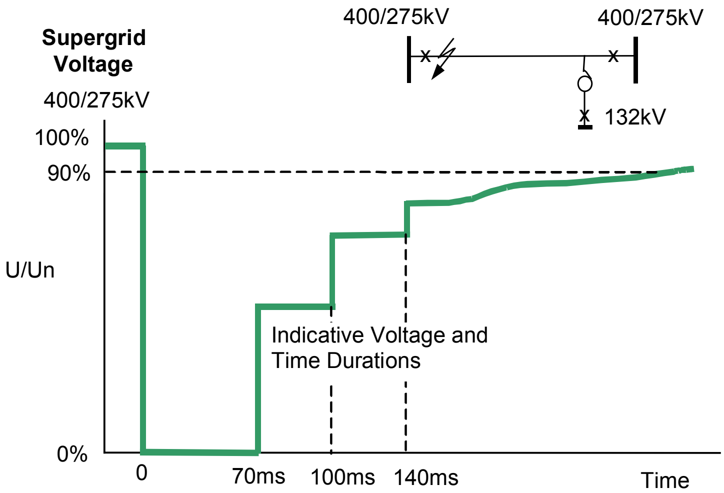
CC.A.4.2 SHORT CIRCUIT FAULTS AT **SUPERGRID VOLTAGE** UP TO 140MS IN DURATION

For short circuit faults at **Supergrid Voltage** up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15 (a) (i). Figures CC.A.4.1 (a) and (b) illustrate two typical examples of voltage recovery for short-circuit faults cleared within 140ms by two circuit breakers (a) and three circuit breakers (b) respectively.



Typical fault cleared in less than 140ms: 2 ended circuit

Figure CC.A.4.1 (a)



Typical fault cleared in 140ms:- 3 ended circuit

Figure CC.A.4.1 (b)

CCA.4.3 **SUPERGRID VOLTAGE** DIPS GREATER THAN 140MS IN DURATION

For balanced **Supergrid voltage** dips having durations greater than 140ms and up to 3 minutes the fault ride through requirement is defined in CC6.3.15 (b) (i) and Figure 5 which is reproduced in this Appendix as Figure CC.A.4.2 and termed the the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at a point on the **GB Transmission System** or **User System** to a disturbance. Rather, each point on the profile (ie the heavy black line) represents a voltage level and an associated time duration which connected **Generating Units, or Power Park Modules** must withstand or ride through.

Figures CC.A.4.3 (c), (d) and (e) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

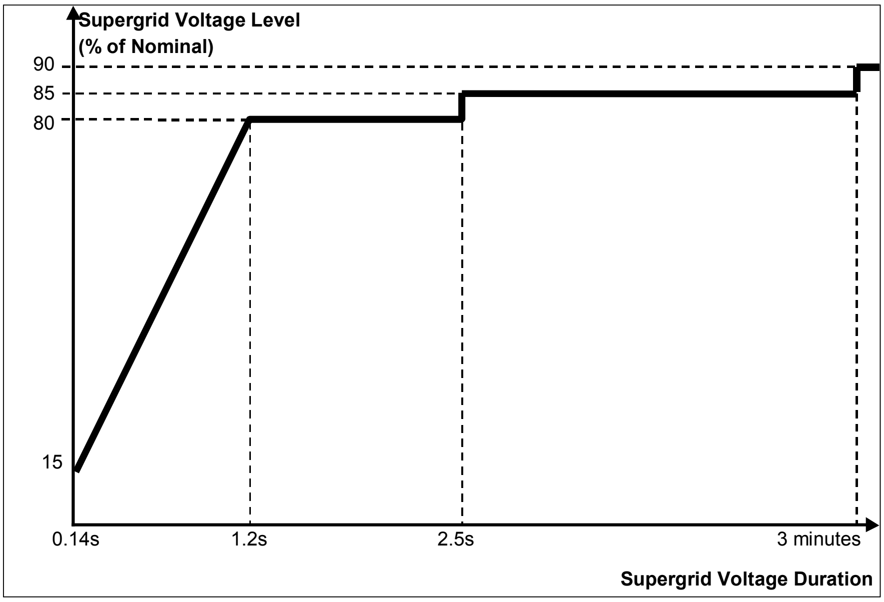
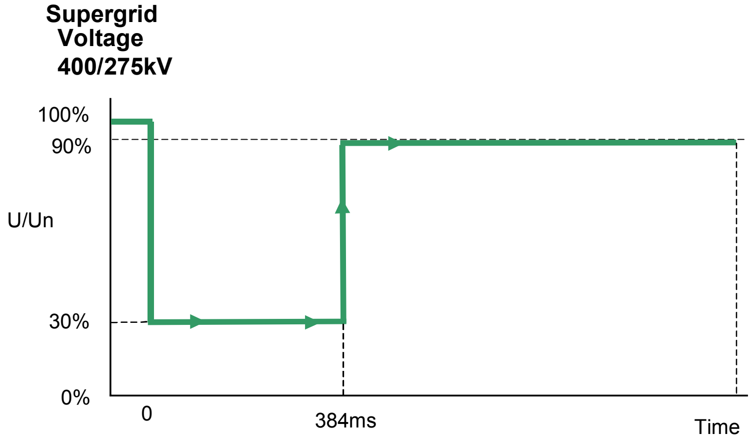
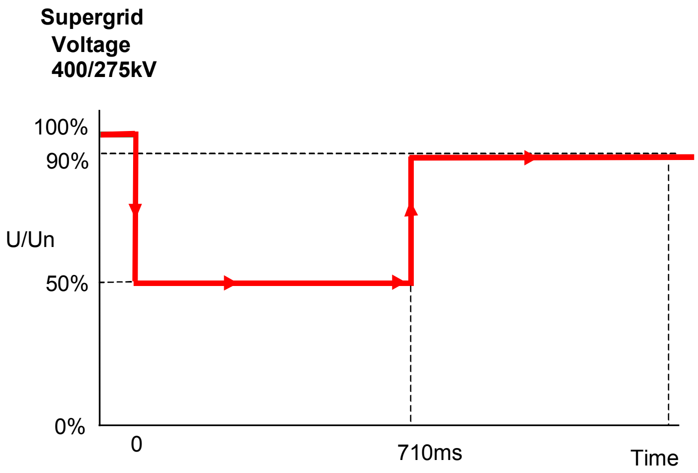


Figure CC.A.4.2



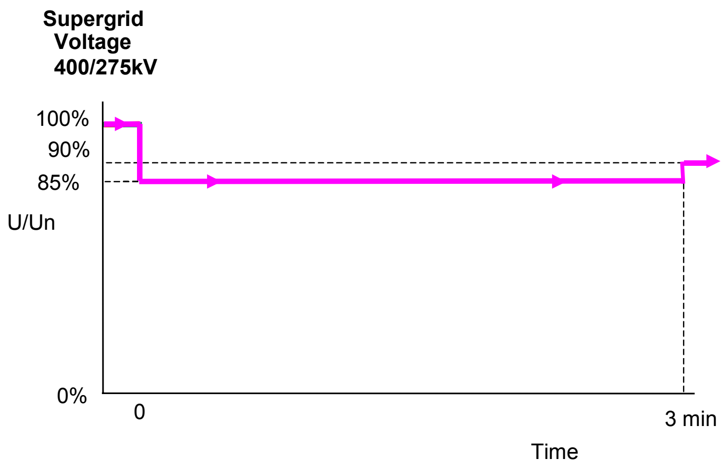
30% retained voltage, 384ms duration

Figure CC.A.4.3(a)



50% retained voltage, 710ms duration

Figure CC.A.4.3(b)



85% retained voltage, 3 minutes duration

Figure CC.A.4.3(c)

…….

< End of CC >

EXTRACTS FROM OPERATING CODE NO.2

OPERATIONAL PLANNING AND DATA PROVISION

OC2.1 INTRODUCTION

OC2.1.1 **Operating Code No. 2** ("**OC2**") is concerned with:

(a) the co-ordination of the release of **Gensets**, the **GB Transmission System** and **Network Operators' Systems** for construction, repair and maintenance;

(b) provision by **NGC** of the **Surpluses** both for the **GB Transmission System** and **System Zones**;

(c) the provision by **Generators** of **Generation Planning Parameters** for **Gensets**, including **CCGT Module Planning Matrices** and **Power Park Module Planning Matrices**, to **NGC** for planning purposes only; and

(d) the agreement for release of **Existing Gas Cooled Reactor Plant** for outages in certain circumstances.

OC2.1.2 (a) **Operational Planning** involves planning, through various timescales, the matching of generation output with forecast **GB Transmission System Demand** together with a reserve of generation to provide a margin, taking into account outages of certain **Generating Units**, **Power Park Modules** and **DC Converters**, and of parts of the **GB Transmission System** and of parts of **Network Operators' Systems** which is carried out to achieve, so far as possible, the standards of security set out in **NGC's Transmission Licence**, each **Relevant Transmission Licensee's Transmission Licence** or **Electricity Distribution Licence** as the case may be.

………

OC2.3 SCOPE

OC2.3.1 **OC2** applies to **NGC** and to **Users** which in **OC2** means:-

(a) **Generators**, other than those which only have **Embedded Small Power Stations** or **Embedded Medium Power Stations**, (and the term **Generator** in this **OC2** shall be construed accordingly);

(b) **Network Operators**; and

(c) **Non-Embedded Customers**; and

(d) **DC Converter Station** owners.

OC2.4.1.2.4 Programming Phase – 2-49 Days Ahead – Daily Resolution

………

(b) By 1100 hours each **Business Day**

Each **Generator** shall provide **NGC** in writing with the best estimate of daily **Output Usable** for each **Genset** for the period from and including day 2 ahead to day 14 ahead, including the forecast return to service date for any such **Generating Unit** or **Power Park Module** subject to **Planned Outage** or breakdown.

………

OC2.4.2 DATA REQUIREMENTS

OC2.4.2.1 When a **Statement of Readiness** under the **Bilateral Agreement** and/or **Construction Agreement** is submitted, and thereafter in calendar week 24 in each calendar year,

(a) each **Generator** shall (subject to OC2.4.2.1(k))in respect of each of its:-

(i) **Gensets** (in the case of the **Generation Planning Parameters**); and

(ii) **CCGT Units** within each of its **CCGT Modules** at a **Large Power Station** (in the case of the **Generator Performance Chart**)

submit to **NGC** in writing the **Generation Planning Parameters** and the **Generator Performance Chart**.

(b) Each shall meet the requirements of CC.6.3.2 and shall reasonably reflect the true operating characteristics of the **Genset**.

(c) They shall be applied (unless revised under this **OC2** or (in the case of the **Generator Performance Chart** only) **BC1** in relation to **Other Relevant Data**) from the **Completion Date,** in the case of the ones submitted with the **Statement of Readiness,** and in the case of the ones submitted in calendar week 24, from the beginning of week 25 onwards.

(d) They shall be in the format indicated in Appendix 1 for these charts and as set out in Appendix 2 for the **Generation Planning Parameters**.

(e) Any changes to the **Generator Performance Chart** or **Generation Planning Parameters** should be notified to **NGC** promptly.

(f) **Generators** should note that amendments to the composition of the **CCGT Module** or **Power Park Module** at **Large Power Stations** may only be made in accordance with the principles set out in PC.A.3.2.~~2~~3 or PC.A.3.2.4 respectively. If in accordance with PC.A.3.2.~~2~~3 or PC.A.3.2.4 an amendment is made, any consequential changes to the **Generation Planning Parameters** should be notified to **NGC** promptly.

(g) **The Generator Performance Chart** must be as described below and demonstrate the limitation on reactive capability of the **System** voltage at 3% above nominal. It must also include any limitations on output due to the prime mover (both maximum and minimum), **Generating Unit** step up transformer or **User System.**

(i) For a **Synchronous Generating Unit** on a **Generating Unit** specific basis at the **Generating Unit** Stator Terminals, ~~and~~ It must include details of the **Generating Unit** transformer parameters. ~~and demonstrate the limitation on reactive capability of the **System** voltage at 3% above nominal. It must~~

~~include any limitations on output due to the prime mover (both maximum and minimum) and **Generating Unit** step-up transformer.~~

(ii) For a **Non-Synchronous Generating Unit** (excluding a **Power Park Unit**) on a **Generating Unit** specific basis at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**).

(iii) For a **Power Park Module**, on a **Power Park Module** specific basis at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**).

(iv) For a **DC Converter** on a **DC Converter** specific basis at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**).

(h) For each **CCGT Unit**, and any other **Generating Unit** or **Power Park Module** whose performance varies significantly with ambient temperature, the **Generator Performance Chart** shall show curves for at least two values of ambient temperature so that **NGC** can assess the variation in performance over all likely ambient temperatures by a process of linear interpolation or extrapolation. One of these curves shall be for the ambient temperature at which the **Generating Unit**'s output, or **CCGT Module** at a **Large Power Station** output, or **Power Park Module's** output, as appropriate, equals its **Registered Capacity.**

(i) The **Generation Planning Parameters** supplied under OC2.4.2.1 shall be used by **NGC** for operational planning purposes only and not in connection with the operation of the **Balancing Mechanism** (subject as otherwise permitted in the **BCs**).

(j) Each **Generator** shall in respect of each of its **CCGT Modules** at **Large Power Stations** submit to **NGC** in writing a **CCGT Module Planning Matrix**. It shall be prepared on a best estimate basis relating to how it is anticipated the **CCGT Module** will be running and which shall reasonably reflect the true operating characteristics of the **CCGT Module.** It will be applied (unless revised under this OC2) from the **Completion Date,** in the case of the one submitted with the **Statement of Readiness,** and in the case of the one submitted in calendar week 24, from the beginning of week 31 onwards. It must show the combination of **CCGT Units** which would be running in relation to any given MW output, in the format indicated in Appendix 3.

Any changes must be notified to **NGC** promptly. **Generators** should note that amendments to the composition of the **CCGT Module** at **Large Power Stations** may only be made in accordance with the principles set out in PC.A.3.2.~~2~~3. If in accordance with PC.A.3.2.~~2~~3 an amendment is made, an updated **CCGT Module Planning Matrix** must be immediately submitted to **NGC** in accordance with this OC2.4.2.1(b).

The **CCGT Module Planning Matrix** will be used by **NGC** for operational planning purposes only and not in connection with the operation of the **Balancing Mechanism**.

(k) Each **Generator** shall in respect of each of its **Cascade Hydro Schemes** also submit the **Generation Planning Parameters** detailed at OC2.A.2.6 to OC2.A.2.10 for each **Cascade Hydro Scheme**. Such parameters need not also be submitted for the individual **Gensets** within such **Cascade Hydro Scheme**.

(l) Each **Generator** shall in respect of each of its **Power Park Modules** at **Large Power Stations** submit to **NGC** in writing a **Power Park Module Planning Matrix**. It shall be prepared on a best estimate basis relating to how it is anticipated the **Power Park Module** will be running and which shall reasonably reflect the operating characteristics of the **Power Park Module.** It will be applied (unless revised under this OC2) from the **Completion Date,** in the case of the one submitted with the **Statement of Readiness,** and in the case of the one submitted in calendar week 24, from the beginning of week 31 onwards. It must show the number of each type of **Power Park Unit** in the **Power Park Module** typically expected to be available to generate, in the format indicated in Appendix 4. The **Power Park Module Planning Matrix** shall be accompanied by a graph showing the variation in MW output with **Intermittent Power Source** (e.g. MW vs wind speed) for the **Power Park Module**. The graph shall indicate the typical value of the **Intermittent Power Source** for the **Power Park Module**.

Any changes must be notified to **NGC** promptly. **Generators** should note that amendments to the composition of the **Power Park Module** at **Large Power Stations** may only be made in accordance with the principles set out in PC.A.3.2.4. If in accordance with PC.A.3.2.4 an amendment is made, an updated **Power Park Module Planning Matrix** must be immediately submitted to **NGC** in accordance with this OC2.4.2.1(a).

The **Power Park Module Planning Matrix** will be used by **NGC** for operational planning purposes only and not in connection with the operation of the **Balancing Mechanism**.

…………..

OC2.4.4 FREQUENCY SENSITIVE OPERATION

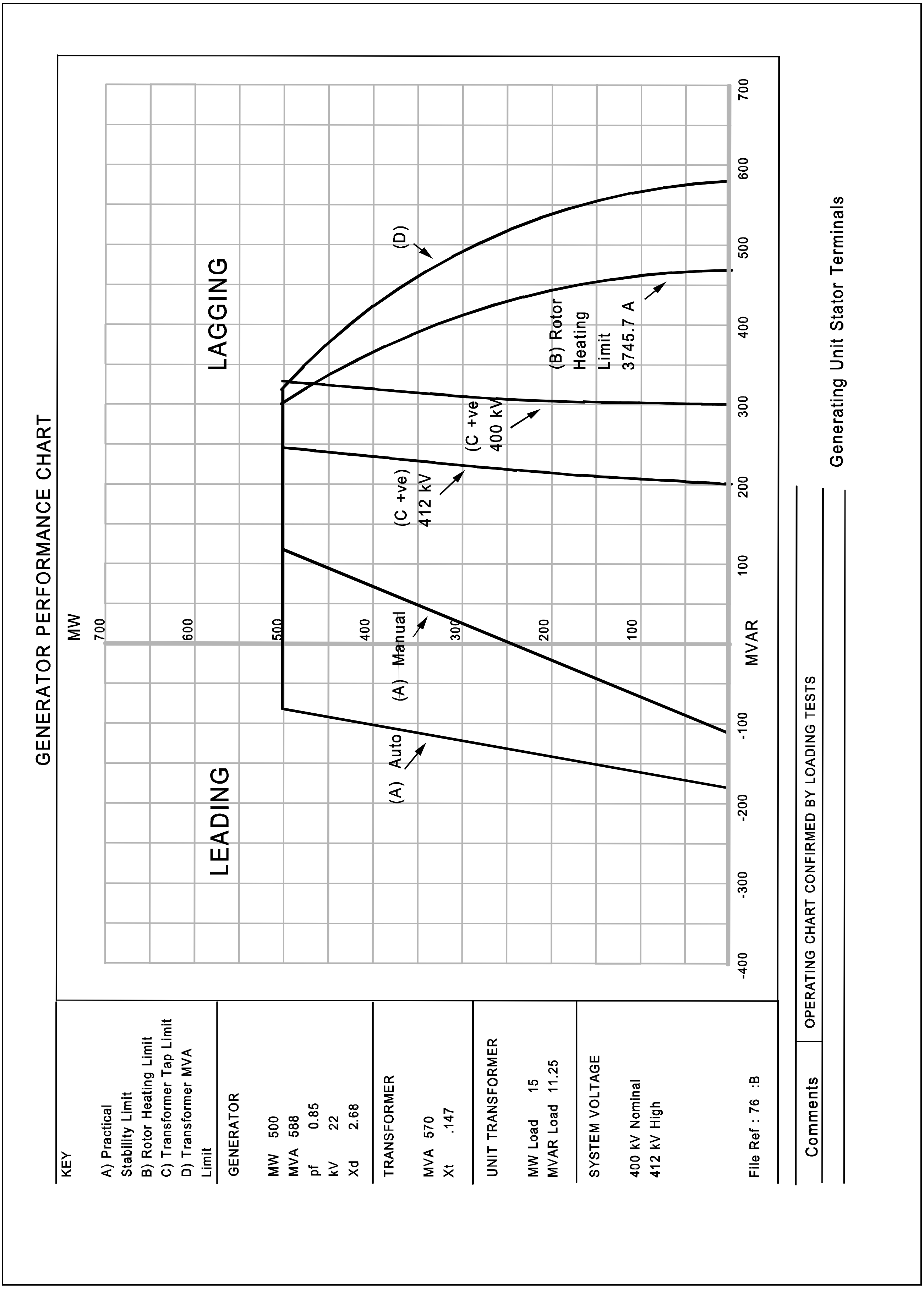
By 1600 hours each Wednesday

…….

OC2.4.4.3 If **NGC** foresees that there will be an insufficiency in **Gensets** operating in a **Frequency Sensitive Mode**, it will contact **Generators** in order to seek to agree (as soon as reasonably practicable) that all or some of the **Gensets** ~~**Generating Units** comprising each **Generator's** relevant **Large Power Stations**~~ (the MW amount being determined by **NGC** but the **Gensets** ~~**Generating Units**~~ involved being determined by the **Generator**) will take outages to coincide with such period as **NGC** shall specify to enable replacement by other **Gensets** which can operate in a **Frequency Sensitive Mode**. If agreement is reached (which unlike the remainder of OC2 will constitute a binding agreement) then such **Generator** will take such outage as agreed with **NGC**. If agreement is not reached, then the provisions of BC2.9.5 may apply.

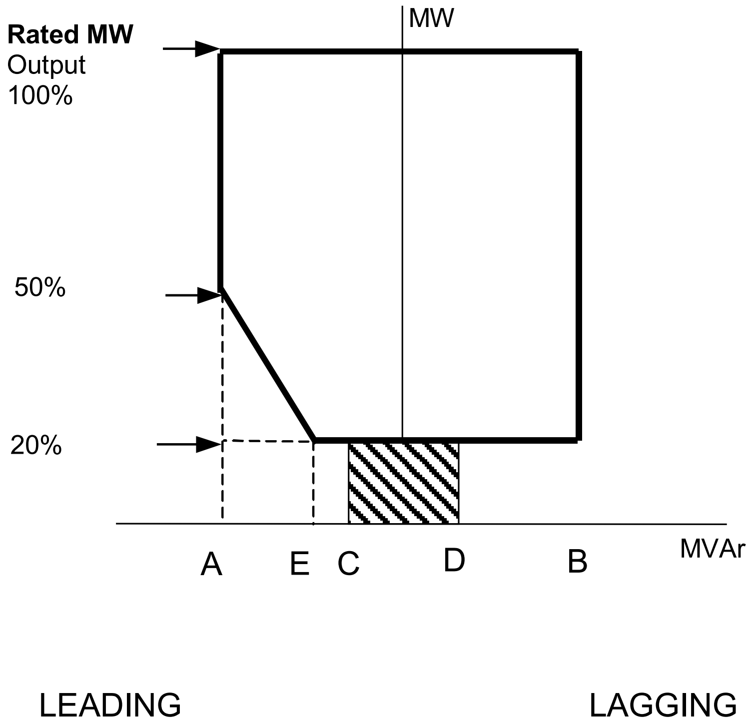
…….

OC2 APPENDIX 1



……..

POWER PARK MODULE PERFORMANCE CHART
AT THE CONNECTION POINT OR USER'S SYSTEM ENTRY POINT



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
Point E is equivalent (in MVAr) to: -12% of **Rated MW** output

OC2 APPENDIX 4

Power Park Module Planning Matrix example form

POWER PARK UNITS AVAILABLE	**POWER PARK UNITS**			
	Type A	Type B	Type C	Type D
Description (Make / Model)				
Number of units				

The **Power Park Module Planning Matrix** may have as many columns as are required to provide information on the different make and model for each type of **Power Park Unit** in a **Power Park Module**. The description is required to assist identification of the **Power Park Units** within the **Power Park Module** and correlation with data provided under the **Planning Code**.

< End of OC2 >

EXTRACTS FROM OPERATING CODE NO. 5

TESTING AND MONITORING

OC5.1 INTRODUCTION

Operating Code No. 5 ("**OC5**") specifies the procedures to be followed by **NGC** in carrying out:

(a) monitoring

(i) of **BM Units** against their expected input or output;

(ii) of compliance by **Users** with the **CC** and in the case of response to **Frequency**, **BC3**; and

(iii) of the provision by **Users** of **Ancillary Services** which they are required or have agreed to provide; and

(b) the following tests (which are subject to **System** conditions prevailing on the day):

(i) tests on **Gensets** and **DC Converters** to test that they have the capability to comply with the **CC** and, in the case of response to **Frequency**, **BC3** and to provide the **Ancillary Services** that they are either required or have agreed to provide;

(ii) tests on **BM Units**, to ensure that the **BM Units** are available in accordance with their submitted **Export and Import Limits, QPNs, Joint BM Unit Data** and **Dynamic Parameters**.

The **OC5** tests include the **Black Start Test** procedure.

In respect of a **Cascade Hydro Scheme** the provisions of **OC5** shall be applied as follows:

(y) in respect of the **BM Unit** for the **Cascade Hydro Scheme** the parameters referred to at OC5.4.1 (a) and (c) in respect of **Commercial Ancillary Services** will be monitored and tested;

(z) in respect of each **Genset** forming part of the **Cascade Hydro Scheme** the parameters referred to at OC5.4.1 (a), (b) and (c) will be tested and monitored. In respect of OC5.4.1 (a) the performance of the **Gensets** will be tested and monitored against their expected input or output derived from the data submitted under BC1.4.2(a)(2). Where necessary to give effect to the requirements for **Cascade Hydro Schemes** in the following provisions of **OC5** the term **Genset** will be read and construed in the place of **BM Unit**.

In respect of **Embedded Exemptable Large Power Stations** the provisions of **OC5** shall be applied as follows:

(1) where there is a **BM Unit** registered in the **BSC** in respect of **Generating Units** the provisions of **OC5** shall apply as written;

(2) In all other cases, in respect of each **Generating Unit** the parameters referred to at OC5.4.1(a), (b) and (c) will be tested and monitored. In respect of OC5.4.1(a) the performance of the **Generating Unit** will be tested and monitored against their expected input or output derived from the data submitted under BC1.4.2(a)(2). Where necessary to give effect to the requirements for such **Embedded Exemptable Large Power Stations** in the provisions of **OC5** the term **Generating Unit** will be read and construed in place of **BM Unit**.

OC5.2 OBJECTIVE

The objectives of **OC5** are to establish:

(a) that **Users** comply with the **CC**;

(b) whether **BM Units** operate in accordance with their expected input or output derived from their **Final Physical Notification Data** and agreed **Bid-Offer Acceptances** issued under **BC2**;

(c) whether each **BM Unit** is available as declared in accordance with its submitted **Export and Import Limits, QPN, Joint BM Unit Data** and **Dynamic Parameters**; and

(d) whether **Generators, DC Converter Station** owners and **Suppliers** can provide those **Ancillary Services** which they are either required or have agreed to provide.

In certain limited circumstances as specified in this **OC5** the output of **CCGT Units** may be verified, namely the monitoring of the provision of **Ancillary Services** and the testing of **Reactive Power** and automatic **Frequency Sensitive Operation**.

OC5.3 SCOPE

OC5 applies to **NGC** and to **Users**, which in **OC5** means:

(a) **Generators**;

(b) **Network Operators;**

(c) **Non-Embedded Customers**; ~~and~~

(d) **Suppliers**; and

(e) **DC Converter Station** owners.

OC5.4 MONITORING

…..

OC5.4.2.2 The relevant **User** will, as soon as possible, provide **NGC** with an explanation of the reasons for the failure and details of the action that it proposes to take to:

(a) enable the **BM Unit** to meet its expected input or output or to provide the **Ancillary Services** it is required or has agreed to provide, within a reasonable period, or

(b) in the case of a **Generating Unit** (excluding a **Power Park Unit**), ~~or~~ **CCGT Module**, **Power Park Module** or **DC Converter** to comply with the **CC** and in the case of response to **Frequency**, **BC3** or to provide the **Ancillary Services** it is required or has agreed to provide, within a reasonable period.

……

OC5.5.1.2 The test, referred to in OC5.5.1.1 and carried out at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the **User's BM Units** should only be to demonstrate that the relevant **BM Unit**:

(a) if active in the **Balancing Mechanism**, meets the ability to operate in accordance with its submitted **Export and Import Limits**, **QPN, Joint BM Unit Data** and **Dynamic Parameters** and achieve its expected input or output which has been monitored under OC5.4; and

(b) meets the requirements of the paragraphs in the **CC** which are applicable to such **BM Units**; and

in the case of a **BM Unit** comprising a **Generating Unit**, ~~or~~ a **CCGT Module**, a **Power Park Module** or a **DC Converter** meets,

(c) the requirements for operation in **Frequency Sensitive Mode** and compliance with the requirements for operation in **Limited Frequency Sensitive Mode** in accordance with CC.6.3.3, BC3.5.2 and BC3.7.2; or

(d) the terms of the applicable **Supplemental Agreement** agreed with the **Generator** to have a **Fast Start Capability**; or

(e) the **Reactive Power** capability registered with **NGC** under **OC2** which shall meet the requirements set out in CC.6.3.2. In the case of a test on a **Generating Unit** within a **CCGT Module** the instruction need not identify the particular **CCGT Unit** within the **CCGT Module** which is to be tested, but instead may specify that a test is to be carried out on one of the **CCGT Units** within the **CCGT Module**.

……

OC5.5.2.2 If monitoring at site is undertaken, the performance of the **BM Unit** will be recorded on a suitable recorder (with measurements, in the case of a **Synchronous Generating Unit**, taken on the **Generating Unit** Stator

Terminals / on the **LV** side of the generator transformer) or in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **Power Park Module** or **DC Converter** at the point of connection in the relevant **User's Control Room**, in the presence of a reasonable number of representatives appointed and authorised by **NGC**. If **NGC** or the **User** requests, monitoring at site will include measurement of the following parameters:

(a) for Steam Turbines: governor pilot oil pressure, valve position and steam pressure; or

(b) for Gas Turbines: Inlet Guide Vane position, Fuel Valve positions, Fuel Demand signal and Exhaust Gas temperature; or

(c) for Hydro Turbines: Governor Demand signal, Actuator Output signal, Guide Vane position; and/or

(d) for Excitation Systems: Generator Field Voltage and **Power System Stabiliser** signal where appropriate.

(e) for **Power Park Modules**: appropriate signals related to the voltage/**Reactive Power**/**Power Factor** control system and the **F~~f~~requency** control system as agreed at the time of connection.

(f) for **DC Converters**: appropriate signals related to the voltage/**Reactive Power**/**Power Factor** control system and the **Frequency** control system as agreed at the time of connection.

………

OC5.5.3 Test and Monitoring Assessment

The pass criteria must be read in conjunction with the full text under the Grid Code reference. The **BM Unit** will pass the test if the criteria below are met:

	Parameter to be Tested	Grid Code Reference	Pass Criteria (to be read in conjunction with the full text under the Grid Code reference)
Voltage Quality	Harmonic Content	CC.6.1.5(a)	Measured harmonic emissions do not exceed the limits specified in the **Bilateral Agreement** or where no such limits are specified, the relevant planning level specified in G5/4.
	Phase Unbalance	CC.6.1.5(b)	The measured maximum **Phase (Voltage) Unbalance** on the **GB Transmission System** should remain, in England and Wales, below 1% and, in Scotland, below 2%.
	Phase Unbalance	CC.6.1.6	In England and Wales, measured infrequent short duration peaks in **Phase** (**Voltage**) **Unbalance** should not exceed the maximum value stated in the **Bilateral Agreement.**
	Voltage Fluctuations	CC.6.1.7(a)	In England and Wales, measured voltage fluctuations at the **Point of Common Coupling** shall not exceed 1% of the voltage level for step changes. Measured voltage excursions other than step changes may be allowed up to a level of 3%. In Scotland, measured voltage fluctuations at a **Point of Common Coupling** shall not exceed the limits set out in **Engineering Recommendation** P28.
	Flicker	CC.6.1.7(b)	Measured voltage fluctuations at a **Point of Common Coupling** shall not exceed, for voltages above 132kV, **Flicker Severity (Short Term)** of 0.8 Unit and **Flicker Severity (Long Term)** of 0.6 Unit, and, for voltages at 132kV and below, shall not exceed **Flicker Severity (Short Term)** of 1.0 Unit and **Flicker Severity (Long Term)** of 0.8 Unit, as set out in **Engineering Recommendation** P28 as current at the **Transfer Date**.

	Parameter to be Tested	Grid Code Reference	Pass Criteria (to be read in conjunction with the full text under the Grid Code reference)
Fault Clearance	Fault Clearance Times	CC.6.2.2.2.2(a) CC.6.2.3.1.1(a)	The fault clearance times shall be in accordance with the **Bilateral Agreement.**
	Back-Up Protection	CC.6.2.2.2.2(b) CC.6.2.3.1.1(b)	The **Back-Up Protection** system provided by **Generators** operates in the times specified in CC.6.2.2.2.2(b). The **Back-Up Protection** system provided by **Network Operators** and **Non-Embedded Customers** operates in the times specified in CC.6.2.3.1.1(b) and with **Discrimination** as specified in the **Bilateral Agreement.**
	Circuit Breaker fail **Protection**	CC.6.2.2.2.2(c) CC.6.2.3.1.1(c)	The circuit breaker fail **Protection** shall initiate tripping so as to interrupt the fault current within 200ms.
Reactive Capability	Reactive Capability	CC.6.3.2 CC.6.3.4	The **Generating Unit** **, DC Converter** or **Power Park Module** will pass the test if it is within ±5% of the reactive capability registered with **NGC** under **OC2** which shall meet the requirements set out in CC.6.3.2. The duration of the test will be for a period of up to 60 minutes during which period the **System** voltage at the **Grid Entry Point** for the relevant **Generating Unit** **, DC Converter** or **Power Park Module** will be maintained by the **Generator** at the voltage specified pursuant to BC2.8 by adjustment of **Reactive Power** on the remaining **Generating Units**, **DC Converters** or **Power Park Modules**, if necessary. Measurements of the **Reactive Power** output under steady state conditions should be consistent with Grid Code requirements i.e. fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages.

	Parameter to be Tested	Grid Code Reference	Pass Criteria (to be read in conjunction with the full text under the Grid Code reference)
Governor System Compliance	**Primary, Secondary** and **High Frequency Response**		The measured response in MW/Hz is within ±5% of the level of response specified in the **Ancillary Services Agreement** for that **Genset.**
	Stability with Voltage	CC.6.3.4	The measured **Active Power** output under steady state conditions of any **Generating Unit** , **DC Converter** or **Power Park Module** directly connected to the **GB Transmission System** should not be affected by voltage changes in the normal operating range.
	Governor Standard	CC.6.3.7(a)	Measurements indicate that the Governor /**Frequency** control system parameters are within the criteria set out in the appropriate governor /**Frequency** control system standard (the version of which to apply being determined within CC.6.3.7).
	Governor Stability	CC.6.3.7(b)	The measured **Generating Unit**, **DC Converter** or **Power Park Module** **Active Power Output** shall be stable over the entire operating range of the **Generating Unit**.
	Governor Droop	CC.6.3.7(c)(ii)	The measured speed governor overall speed **droop** should be between 3% and 5%.
	Governor Deadband	CC.6.3.7.(c)(iii)	Except for the **Steam Unit** within a **CCGT Module,** the measured speed governor/**Ffrequency** control system deadband shall be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz).
	Target Frequency	CC.6.3.7(d)	**Target Frequency** settings over at least the range 50 ±0.1 Hz shall be available.
	Response Capability	CC.6.3.7(e) CC.A.3	The measured frequency response of each **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 shall meet requirement profile contained in **Connection Conditions** Appendix 3. Similarly for **DC Converters** with **Completion Dates** on or after 1 April 2005 and **Power Park Modules** using the **GB Transmission System** on or after 1 January 2006 (irrespective of its **Completion Date** excepting those in Scotland with **Completion Date** before 1 April 2005).
	Limited High Frequency Response	BC3.7.2(b)	The measured response is within the requirements of BC3.7.2. i.e. the measured rate of change of **Active Power** output must be at least 2% of output per 0.1Hz deviation of **System Frequency** above 50.4Hz.
	Output at reduced **System Frequency**	CC.6.3.3 BC3.5.1	For variations in **System Frequency** exceeding 0.1Hz within a period of less than 10 seconds, the **Active Power** output is within ±0.2% of the requirements of CC.6.3.3 when monitored at prevailing external air temperatures of up to 25ºC.

	Parameter to be Tested	Grid Code Reference	Pass Criteria (to be read in conjunction with the full text under the Grid Code reference)
	Fast Start		The **Fast Start Capability** requirements of the **Ancillary Services Agreement** for that **Genset** are met.
	Black Start	OC.5.7.1	The relevant **Generating Unit** or **Power Park Module** is **Synchronised** to the **System** within two hours of the **Auxiliary Gas Turbine(s)** or **Auxiliary Diesel Engine(s)** being required to start.
	Excitation System/ Voltage Control	CC.6.3.8(a) (b) & BC2.11.2	Measurements of the continuously acting automatic excitation control system are required to demonstrate the provision of: (i) constant terminal voltage control; or (ii) zero MVAr transfer;or, (iii) voltage control with a **Slope** ~~droop~~ of the **Generating Unit** , **DC Converter** or **Power Park Module** as applicable without instability over the entire operating range of the **Generating Unit**, **DC Converter** or **Power Park Module**. The measured performance of the automatic excitation or voltage control system should also meet the requirements (including **Power System Stabiliser** performance) specified in the **Bilateral Agreement**.

	Parameter to be Tested	Grid Code Reference	Pass Criteria
Dynamic Parameters	**Export and Import Limits, QPN, Joint BM Unit Data** and **Dynamic Parameters**	OC5	The **Export and Import Limits, QPN, Joint BM Unit Data** and **Dynamic Parameters** under test are within 2½% of the declared value being tested. The duration of the test will be consistent with and sufficient to measure the relevant expected input or output derived from the **Final Physical Notification Data** and **Bid-Offer Acceptances** issued under BC2 which are still in dispute following the procedure in OC5.4.2.
	Synchronisation time	BC2.5.2.3	**Synchronisation** takes place within ±5 minutes of the time it should have achieved **Synchronisation.** The duration of the test will be consistent with and sufficient to measure the relevant expected input or output derived from the **Final Physical Notification Data** and **Bid-Offer Acceptances** issued under BC2 which are still in dispute following the procedure in OC5.4.2.
	Run-up rates	OC5	Achieves the instructed output and, where applicable, the first and/or second intermediate breakpoints, each within ±3 minutes of the time it should have reached such output and breakpoints from **Synchronisation** (or break point, as the case may be), calculated from the run-up rates in its **Dynamic Parameters.** The duration of the test will be consistent with and sufficient to measure the relevant expected input or output derived from the **Final Physical Notification Data** and **Bid-Offer Acceptances** issued under BC2 which are still in dispute following the procedure in OC5.4.2.
	Run-down rates	OC5	Achieves the instructed output within ±5 minutes of the time, calculated from the run-down rates in its **Dynamic Parameters.** The duration of the test will be consistent with and sufficient to measure the relevant expected input or output derived from the **Final Physical Notification Data** and **Bid-Offer Acceptances** issued under BC2 which are still in dispute following the procedure in OC5.4.2.

Due account will be taken of any conditions on the **System** which may affect the results of the test. The relevant **User** must, if requested, demonstrate, to **NGC's** reasonable satisfaction, the reliability of the suitable recorders, disclosing calibration records to the extent appropriate.

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OC5.6 DISPUTE RESOLUTION

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OC5.6.2 If a **BM Unit** fails the test, the **User** shall submit revised **Export and Import Limits, QPN, Joint BM Unit Data** and/or **Dynamic Parameters**, or in the case of a **BM Unit** comprising a **Generating Unit**, ~~or a~~ **CCGT Module**, **DC Converter** or **Power Park Module**, the **User** may amend, with **NGC**'s approval, the relevant registered parameters of that **Generating Unit**, ~~or~~ **CCGT Module**, **DC Converter** or **Power Park Module**, as the case may be, relating to the criteria, for the period of time until the **BM Unit** can achieve the parameters previously registered, as demonstrated in a re-test.

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<End of OC5>

EXTRACTS FROM OPERATING CODE NO.7

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OC7.3 SCOPE

OC7.3.1 **OC7** applies to **NGC** and to **Users,** which in **OC7** means:-

(a) **Generators** (other than those which only have **Embedded Small Power Stations** or **Embedded Medium Power Stations**);

(b) **Network Operators;**

(c) **Non-Embedded Customers**;

(d) **Suppliers** (for the purposes of **GB Transmission System Warnings**); ~~and~~

(e) **Externally Interconnected System Operators** (for the purposes of **GB Transmission System Warnings**); and

(f) **DC Converter Station** owners.

The procedure for operational liaison by **NGC** with **Externally Interconnected System Operators** is set out in the **Interconnection Agreement** with each **Externally Interconnected System Operator.**

In Scotland OC7.6 also applies to **Relevant Transmission Licensees.**

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OC7.4.5.4 **Operations** caused by another **Operation** or by an **Event**

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OC7.4.5.9 (a) A **Network Operator** may pass on the information contained in a notification to it from **NGC** under OC7.4.5.1, to a **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System**, or to a **DC Converter Station** owner with a **DC Converter** connected to its **System**, or to the operator of another **User System** connected to its **System** (which, for the avoidance of doubt, could be another **Network Operator**), in connection with reporting the equivalent of an **Operation** under the **Distribution Code** (or the contract pursuant to which that **Generating Unit** or **Power Park Module** or other **User System**, or to a **DC Converter Station** is connected to the **System** of that **Network Operator**) (if the **Operation** on the **GB Transmission System** caused it).

(b) A **Generator** may pass on the information contained in a notification to it from **NGC** under OC7.4.5.1, to another **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System,** or to the operator of a **User System** connected to its **System** (which, for the avoidance of doubt, could be a **Network Operator**), if it is required (by a contract pursuant to which that **Generating Unit** or that **Power Park Module** or that **User System** is connected to its **System**) to do so in connection with the equivalent of an **Operation** on its **System** (if the **Operation** on the **GB Transmission System** caused it).

…..

OC7.4.6.10 (a) A **Network Operator** may pass on the information contained in a notification to it from **NGC** under OC7.4.6.1, to a **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System** or to a **DC Converter Station** owner with a **DC Converter** connected to its **System** or to the operator of another **User System** connected to its **System** (which, for the avoidance of doubt, could be a **Network Operator**), in connection with reporting the equivalent of an **Event** under the **Distribution Code** (or the contract pursuant to which that **Generating Unit** or **Power Park Module** or **DC Converter** or other **User System** is connected to the **System** of that **Network Operator**) (if the **Event** on the **GB Transmission System** caused or exacerbated it).

(b) A **Generator** may pass on the information contained in a notification to it from **NGC** under OC7.4.6.1, to another **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System** or to the operator of a **User System** connected to its **System** (which, for the avoidance of doubt, could be a **Network Operator**), if it is required (by a contract pursuant to which that **Generating Unit** or that **Power Park Module** or that **User System** is connected to its **System**) to do so in connection with the equivalent of an **Event** on its **System** (if the **Event** on the **GB Transmission System** caused or exacerbated it).

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OC7.4.6.12 When an **Event** relating to a **Generating Unit**, **Power Park Module** or **DC Converter**, has been reported to **NGC** by a **Generator** or **DC Converter Station** owner under OC7.4.6 and it is necessary in order for the **Generator** or **DC Converter Station** owner to assess the implications of the **Event** on its **System** more accurately, the **Generator** or **DC Converter Station** owner may ask **NGC** for details of the fault levels from the **GB Transmission System** to that **Generating Unit** , **Power Park Module** or **DC Converter** at the time of the **Event**, and **NGC** will, as soon as reasonably practicable, give the **Generator** or **DC Converter Station** owner that information provided that **NGC** has that information.

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OC7.5 PROCEDURE IN RELATION TO **INTEGRAL EQUIPMENT TESTS**

OC7.5.1 This section of the **Grid Code** deals with **Integral Equipment Tests**. It is designed to provide a framework for the exchange of relevant information and for discussion between **NGC** and certain **Users** in relation to **Integral Equipment Tests.**

OC7.5.2 An **Integral Equipment Test** :-

(a) is carried out in accordance with the provisions of this OC7.5 at:-

i) a **User Site**,
ii) a **Transmission Site**, ~~or,~~
iii) an **Embedded Large Power Station**~~;~~or,
iv) an **Embedded DC Converter Station;**

(b) will normally be undertaken during commissioning or re-commissioning of **Plant** and/or **Apparatus**;

(c) may, in the reasonable judgement of the person wishing to perform the test, cause, or have the potential to cause, an **Operational Effect** on a part or parts of the **Total System** but which with prior notice is unlikely to have a materially adverse effect on any part of the **Total System**; and

(d) may form part of an agreed programme of work.

………

OC7.5.8 (a) Where **NGC** receives notification of a proposed **IET** from a **User**, **NGC** will consult those other **Users** whom it reasonably believes may be affected by the proposed **IET** to seek their views. Information relating to the proposed **IET** may be passed on by **NGC** with the prior agreement of the proposer. However it is not necessary for **NGC** to obtain the agreement of any such **User** as **IETs** should not involve the application of irregular, unusual or extreme conditions. **NGC** may however consider any comments received when deciding whether or not to agree to an **IET**.

(b) In the case of an **Embedded Large Power Station** or **Embedded DC Converter Station**, the **Generator** or **DC Converter Station** owner as the case may be must liaise with both **NGC** and the relevant **Network Operator**. **NGC** will not agree to an **IET** relating to such **Plant** until the **Generator** or **DC Converter Station** owner has shown that it has the agreement of the relevant **Network Operator**.

(c) A **Network Operator** will liaise with **NGC** as necessary in those instances where it is aware of an **Embedded Small Power Station** or an **Embedded Medium Power Station** which intends to perform tests which in the reasonable judgement of the **Network Operator** may cause an **Operational Effect** on the **GB Transmission System**.

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WARNING TYPE	Grid Code	FORMAT	to : for ACTION	to : for INFORMATION	TIMESCALE	WARNING OF/OR CONSEQUENCE	Response From Recipients
GB TRANSMISSION SYSTEM WARNING - Inadequate System Margin	OC7.4.8.5	Fax or other electronic means	Generators, Suppliers, Externally Interconnected System Operators, **DC Converter Station** owners	Network Operators, Non-Embedded Customers	All timescales when at the time there is not a high risk of Demand reduction. Primarily 1200 hours onwards for a future period.	Insufficient generation available to meet forecast Demand plus Operating Margin Notification that if not improved Demand reduction may be instructed. (Normal initial warning of insufficient System Margin)	Offers of increased availability from Generators or **DC Converter Station** owner and Interconnector Users. Suppliers notify **NGC** of any additional Customer Demand Management that they will initiate.
GB TRANSMISSION SYSTEM WARNING - High Risk of Demand Reduction	OC7.4.8.6	Fax or other electronic means	Generators, Suppliers, Network Operators, Non-Embedded Customers, Externally Interconnected System Operators, **DC Converter** Station owners		All timescales where there is a high risk of Demand reduction. Primarily 1200 hours onwards for a future period.	Insufficient generation available to meet forecast Demand plus Operating Margin and /or a high risk of Demand reduction being instructed. (May be issued locally as Demand reduction risk only for circuit overloads)	Offers of increased availability from Generators or **DC Converter Station** owner and Interconnector Users. Suppliers notify **NGC** of any additional Customer Demand Management that they will initiate. Specified Network Operators and Non-Embedded Customers to prepare their Demand reduction arrangements and take actions as necessary to enable compliance with **NGC** instructions that may follow. (Percentages of Demand reduction above 20 % may not be achieved if **NGC** has not issued the warning by 16.00 hours the previous day).
GB TRANSMISSION SYSTEM WARNING - Demand Control Imminent	OC7.4.8.7	Fax/ Telephone or other electronic means	**Specified Users only :** (to whom an instruction is to be given) Network Operators, Non-Embedded Customers	None	within 30 minutes of anticipated instruction.	Possibility of Demand reduction within 30 minutes.	Network Operators specified to prepare to take action as necessary to enable them to comply with any subsequent **NGC** instruction for Demand reduction.
GB TRANSMISSION SYSTEM WARNING - Risk of System Disturbance	OC7.4.8.8	Fax/ Telephone or other electronic means	Generators, DC Converter Station owners Network Operators, Non-Embedded Customers, Externally Interconnected System Operators who may be affected.	Suppliers	Control room timescales	Risk of, or widespread system disturbance to whole or part of the **GB Transmission System**	Recipients take steps to warn operational staff and maintain plant or apparatus such that they are best able to withstand the disturbance.

< End of OC7 >

EXTRACTS FROM OPERATING CODE NO.10

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OC10.3 SCOPE

OC10.3.1 **OC10** applies to **NGC** and to **Users**, which in **OC10** means:-

(a) **Generators** (other than those which only have **Embedded Small Power Stations** and/or **Embedded Medium Power Stations**);

(b) **Network Operators**;~~ and~~

(c) **Non-Embedded Customers**; and

(d) **DC Converter Station** owners.

The procedure for **Event** information supply between **NGC** and **Externally Interconnected System Operators** is set out in the **Interconnection Agreement** with each **Externally Interconnected System Operator**.

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OC10.4.1.2 Written Reporting of **Events** by **NGC** to **Users**

In the case of an **Event** which was initially reported by **NGC** to a **User** orally and subsequently determined by the **User** to be a **Significant Incident**, and accordingly notified by the **User** to **NGC** pursuant to **OC7**, **NGC** will give a written report to the **User**, in accordance with **OC10**. The **User** will not pass on the report to other affected **Users** but:

(a) a **Network Operator** may use the information contained therein in preparing a written report to a **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System** or to a **DC Converter Station** owner with a **DC Converter** connected to its **System** or to another operator of a **User System** connected to its **System** in connection with reporting the equivalent of a **Significant Incident** under the **Distribution Code** (or other contract pursuant to which that **Generating Unit** or that **Power Park Module** or that **DC Converter** or **User System** is connected to its **System**) (if the **Significant Incident** on the **GB Transmission System** caused or exacerbated it); and

(b) a **Generator** may use the information contained therein in preparing a written report to another **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System** or to the operator of a **User System** connected to its **System** if it is required (by a contract pursuant to which that **Generating Unit** or a **Power Park Module** or that is connected to its **System**) to do so in connection with the equivalent of a **Significant Incident** on its **System** (if the **Significant Incident** on the **GB Transmission System** caused or exacerbated it).

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OC10.4.2.3 **NGC** or a **User** may also request that:-

(i) an **Externally Interconnected System Operator** and/or

(ii) **Interconnector User** or

(iii) (in the case of a **Network Operator**) a **Generator** with a **Generating Unit** or a **Power Park Module** or a **DC Converter Station** owner with **DC Converter** connected to its **System** or another **User System** connected to its **System** or

(iv) (in the case of a **Generator**) another **Generator** with a **Generating Unit** or a **Power Park Module** connected to its **System** or a **User System** connected to its **System**.

be included in the joint investigation.

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APPENDIX

MATTERS, IF APPLICABLE TO THE **SIGNIFICANT INCIDENT** AND TO THE RELEVANT **USER** (OR **NGC**, AS THE CASE MAY BE,) TO BE INCLUDED IN A WRITTEN REPORT GIVEN IN ACCORDANCE WITH OC10.4.1 AND OC10.4.2

1. Time and date of **Significant Incident**.

2. Location.

3. **Plant** and/or **Apparatus** directly involved (and not merely affected by the **Event**).

4. Description of **Significant Incident**.

5. **Demand** (in MW) and/or generation (in MW) interrupted and duration of interruption.

6. **Generating Unit** **, Power Park Module** or **DC Converter** - **Frequency** response (MW correction achieved subsequent to the **Significant Incident**).

7. **Generating Unit, Power Park Module** or **DC Converter** - Mvar performance (change in output subsequent to the **Significant Incident**).

8. Estimated time and date of return to service.

< End of OC10>

EXTRACTS FROM OPERATING CODE NO.11

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OC11.3 SCOPE

OC11.3.1 **OC11** applies to **NGC** and to **Users**, which in **OC11** means:-

(a) **Generators;**

(b) **Network Operators**; ~~and~~

(c) **Non-Embedded Customers**; and

(d) **DC Converter Station** owners.

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< End of OC11 >

EXTRACTS FROM OPERATING CODE NO.12

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OC12.3 SCOPE

OC12 applies to **NGC** and to **Users**, which in **OC12** means:-

(a) **Generators;**

(b) **Network Operators**;~~ and~~

(c) **Non-Embedded Customers**; and

(d) **DC Converter Station** owners.

The procedure for the establishment of **System Tests** on the **GB Transmission System**, with **Externally Interconnected System Operators** which do not affect any **User,** is set out in the **Interconnection Agreement** with each **Externally Interconnected System Operator**. The position of **Externally Interconnected System Operators** and **Interconnector Users** is also referred to in OC12.4.2.

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< End of OC12 >

EXTRACTS FROM BALANCING CODE No 1

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BC1.4.2 Day Ahead Submissions

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(a) **Physical Notifications**

Physical Notifications, being the data listed in **BC1** Appendix 1 under that heading, are required by **NGC** at 11:00 hours each day for each **Settlement Period** of the next following **Operational Day,** in respect of **BM Units**:-

(1) **BM Units:-**

(i) with a **Demand Capacity** with a magnitude of 50MW or more in England and Wales or 5MW or more in Scotland; or

(ii) comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) and/or **CCGT Modules** ~~,~~ and/or **Power Park Modules** in each case at **Large Power Stations** and **Medium Power Stations;** or

(iii) where the **BM Participant** chooses to submit **Bid-Offer Data** in accordance with BC1.4.2(d) for **BM Units** not falling within (i) or (ii) above,

and

(2) each **Generating Unit**.

Physical Notifications may be submitted to **NGC** by **BM Participants,** for the **BM Units**, and **Generating Units**, specified in this BC1.4.2(a) at an earlier time, or **BM Participants** may rely upon the provisions of BC1.4.5 to create the **Physical Notifications** by data defaulting pursuant to the **Grid Code** utilising the rules referred to in that paragraph at 11:00 hours in any day.

Physical Notifications (which must comply with the limits on maximum rates of change listed in **BC1** Appendix 1) must, subject to the following operating limits, represent the **User's** best estimate of expected input or output of **Active Power** and shall be prepared in accordance with **Good Industry Practice**. **Physical Notifications** for any **BM Unit**, and any **Generating Units**, should normally be consistent with the **Dynamic Parameters** and **Export and Import Limits** and must not reflect any **BM Unit** or any **Generating Units**, proposing to operate outside the limits of its **Demand Capacity** and (and in the case of **BM Units**) **Generation Capacity** and, in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) or **CCGT Module**~~,~~ or **Power Park Module**~~,~~ its **Registered Capacity.**

These **Physical Notifications** provide, amongst other things, indicative **Synchronising** and **De-Synchronising** times to **NGC** in respect of any **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) or **CCGT Module**~~,~~ or **Power Park Module** and provide an indication of significant **Demand** changes in respect of other **BM Units**.

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(f) <u>**Other Relevant Data**</u>

By 11:00 hours each day each **BM Participant,** in respect of each of its **BM Units** and **Generating Units** for which **Physical Notifications** are being submitted, shall, if it has not already done so, submit to **NGC** (save in respect of item (vi) where the item shall be submitted only when reasonably required by **NGC**), in respect of the next following **Operational Day** the following:

(i) in the case of a **CCGT Module**, a **CCGT Module Matrix** as described in **BC1** Appendix 1;

(ii) details of any special factors which in the reasonable opinion of the **BM Participant** may have a material effect or present an enhanced risk of a material effect on the likely output (or consumption) of such **BM Unit(s)**. Such factors may include risks, or potential interruptions, to **BM Unit** fuel supplies, or developing plant problems, details of tripping tests, etc. This information will normally only be used to assist in determining the appropriate level of **Operating Margin** that is required under OC2.4.6;

(iii) in the case of **Generators**, any temporary changes, and their possible duration, to the **Registered Data** of such **BM Unit**;

(iv) in the case of **Suppliers**, details of **Customer Demand Management** taken into account in the preparation of its **BM Unit Data**; and

(v) details of any other factors which **NGC** may take account of when issuing **Bid-Offer Acceptances** for a **BM Unit** (e.g., **Synchronising** or **De-Synchronising** Intervals, the minimum notice required to cancel a **Synchronisation**, etc).

<u>(vi)</u> in the case of a **Cascade Hydro Scheme**, the **Cascade Hydro Scheme Matrix** as described in **BC1** Appendix 1.

<u>(vii) in the case of a **Power Park Module**, a **Power Park Module Availability Matrix** as described in **BC1** Appendix 1.</u>

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BC1.6.1 **<u>User System</u>** <u>Data from</u> **<u>Network Operators</u>**

(a) By 1000 hours each day each **Network Operator** will submit to **NGC** in writing, confirmation or notification of the following in respect of the next **Operational Day**:

(i) constraints on its **User System** which **NGC** may need to take into account in operating the **GB Transmission System**. In this BC1.6.1 the term "constraints" shall include restrictions on the operation of **Embedded CCGT Units** <u>, and/or</u> **<u>Embedded Power Park Modules</u>** as a result of the **User System** to which the **CCGT Unit** <u>and/or</u> **<u>Power Park Module</u>** is connected at the **User System Entry Point** being operated or switched in a particular way, for example, splitting the relevant busbar. It is a matter for the **Network Operator** and the **Generator** to arrange the operation or switching, and to deal with any resulting consequences. The **Generator,** after consultation with the **Network Operator**, is responsible for ensuring that no **BM Unit Data** submitted to **NGC** can result in the violation of any such constraint on the **User System**.

(ii) the requirements of voltage control and Mvar reserves which **NGC** may need to take into account for **System** security reasons.

(b) The form of the submission will be:

(i) that of a **BM Unit** output or consumption (for MW and for Mvar, in each case a fixed value or an operating range, on the **User System** at the **User System Entry Point**, namely in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2) on the higher voltage side of the generator step-up transformer<u>, or in the case of a</u> **<u>Power Park Module</u>**<u>, at the point of connection</u>) required for particular **BM Units** (identified in the submission) connected to that **User System** for each **Settlement Period** of the next **Operational Day**;

(ii) adjusted in each case for MW by the conversion factors applicable for those **BM Units** to provide output or consumption at the relevant **Grid Supply Points**.

(c) At any time and from time to time, between 1000 hours each day and the expiry of the next **Operational Day**, each **Network Operator** must submit to **NGC** in writing any revisions to the information submitted under this BC1.6.1.

BC1.6.2 <u>Notification of Times to</u> **<u>Network Operators</u>**

NGC will make available indicative **Synchronising** and **De-Synchronising** times to each **Network Operator**, but only relating to **BM Units** comprising a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC1.2)~~,~~<u> or a</u> **<u>Power Park Module</u>** or a **CCGT Module Embedded** within that **Network Operator's User System** and those **Gensets** directly connected to the **GB Transmission System** which **NGC** has identified under **OC2** as being those which may, in the reasonable opinion of **NGC**, affect the integrity of that **User System**. If in preparing for the operation of the **Balancing Mechanism**, **NGC** becomes aware that a **BM Unit** directly connected to the **GB Transmission System** may, in its reasonable opinion, affect the integrity of that other **User System** which, in the case of a **BM Unit** comprising a **Generating Unit** (as defined in the Glossary and

Definitions and not limited by BC1.2) or a **CCGT Module**~~,~~ or a **Power Park Module**, it had not so identified under **OC2**, then **NGC** may make available details of its indicative **Synchronising** and **De-Synchronising** times to that other **User** and shall inform the relevant **BM Participant** that it has done so, identifying the **BM Unit** concerned.

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APPENDIX 1

BM UNIT DATA

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BC1.A.1.8 **Power Park Module Availability Matrix**

BC1.A.1.8.1 **Power Park Module Availability Matrix** showing the number of each type of **Power Park Units** expected to be available is illustrated in the example form below. The **Power Park Module Availability Matrix** is designed to achieve certainty in knowing the number of **Power Park Units Synchronised** to meet the **Physical Notification** and to achieve a **Bid-Offer Acceptance**. The **Power Park Module Availability Matrix** may have as many columns as are required to provide information on the different make and model for each type of **Power Park Unit** in a **Power Park Module**. The description is required to assist identification of the **Power Park Units** within the **Power Park Module** and correlation with data provided under the **Planning Code**.

Power Park Module Availability Matrix example form

POWER PARK UNIT AVAILABILITY	**POWER PARK UNITS**			
	Type A	Type B	Type C	Type D
Description (Make/Model)				
Number of units				

BC1.A.1.8.2 In the absence of the correct submission of a **Power Park Module Availability Matrix** the last submitted (or deemed submitted) **Power Park Module Availability Matrix** shall be taken to be the **Power Park Module Availability Matrix** submitted hereunder.

BC1.A.1.8.3 **NGC** will rely on the **Power Park Units** specified in such **Power Park Module Availability Matrix** running as indicated in the **Power Park Module Availability Matrix** when it issues an instruction in respect of the **Power Park Module**;

BC1.A.1.8.4 Subject as provided in PC.A.3.2.4 any changes to the **Power Park Module Availability Matrix** must be notified immediately to **NGC** in accordance with the relevant provisions of **BC1**.

APPENDIX 2

DATA TO BE MADE AVAILABLE BY NGC

BC1.A.2.1 Initial Day Ahead Demand Forecast

Normally by 09:00 hours each day, values (in MW) for each **Settlement Period** of the next following **Operational Day** of the following data items:-

i) Initial forecast of **GB National Demand;**

ii) Initial forecast of **Demand** for a number of predetermined constraint groups.

BC1.A.2.2 Initial Day Ahead Market Information

Normally by 12:00 hours each day, values (in MW) for each **Settlement Period** of the next following **Operational Day** of the following data items:-

i) Initial National **Indicated Margin**

This is the difference between the sum of **BM Unit** MELs and the forecast of **GB Transmission System Demand**.

ii) Initial National **Indicated Imbalance**

This is the difference between the sum of **Physical Notifications** for **BM Units** comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) or **CCGT Modules** or **Power Park Modules** and the forecast of **GB Transmission System Demand**.

iii) Forecast of **GB Transmission System Demand.**

BC1.A.2.3 Current Day and Day Ahead Updated Market Information

Data will normally be made available by the times shown below for the associated periods of time:

Target Data Release Time	Period Start Time	Period End Time
02:00	02:00 D0	05:00 D+1
10:00	10:00 D0	05:00 D+1
16:00	05:00 D+1	05:00 D+2
16:30	16:30 D0	05:00 D+1
22:00	22:00 D0	05:00 D+2

In this table, D0 refers to the current day, D+1 refers to the next day and D+2 refers to the day following D+1.

In all cases, data will be ½ hourly average MW values calculated by **NGC**. Information to be released includes:-

National Information

i) National **Indicated Margin**;

ii) National **Indicated Imbalance**;

iii) Updated forecast of **GB Transmission System Demand.**

<u>Constraint Boundary Information (for each Constraint Boundary)</u>

i) **Indicated Constraint Boundary Margin**;

This is the difference between the Constraint Boundary Transfer limit and the difference between the sum of **BM Unit** MELs and the forecast of local **Demand** within the constraint boundary.

ii) Local **Indicated Imbalance**;

This is the difference between the sum of **Physical Notifications** for **BM Units** comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC1.2) or **CCGT Modules** <u>or **Power Park Modules**</u> and the forecast of local **Demand** within the constraint boundary.

iii) Updated forecast of the local **Demand** within the constraint boundary**.**

< End of BC1 >

EXTRACTS FROM BALANCING CODE NO 2

…….

BC2.5.4 Operation in the absence of instructions from **NGC**

In the absence of any **Bid-Offer Acceptances**, **Ancillary Service** instructions issued pursuant to BC2.8 or **Emergency Instructions** issued pursuant to BC2.9:

(a) as provided for in BC3, each **Synchronised Genset** producing **Active Power** must operate at all times in **Limited Frequency Sensitive Mode** (unless instructed in accordance with BC3.5.4 to operate in **Frequency Sensitive Mode**);

(b) in the absence of any Mvar **Ancillary Service** instructions, the Mvar output of each **Synchronised Genset** should be 0 Mvar upon **Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**. For the avoidance of doubt, in the case of a **Genset** comprising of **Non-Synchronous Generating Units**, **Power Park Modules** or **DC Converters** the steady state tolerance allowed in CC.6.3.2(b) may be applied;

(c) (i) subject to the provisions of 2.5.4(c) (ii) below, the excitation system or the voltage control system, unless otherwise agreed with **NGC**, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service, with any constant **Reactive Power** output control mode or constant **Power Factor** output control mode always disabled, unless agreed otherwise with **NGC**. In the event of any change in **System** voltage, a **Generator** must not take any action to override automatic Mvar response which is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by **NGC** or unless immediate action is necessary to comply with **Stability Limits** or unless constrained by plant operational limits or safety grounds (relating to personnel or plant);

(ii) In the case of all **Gensets** comprising **Non-Synchronous Generating Units**, **DC Converters** and **Power Park Modules** only when operating below 20 % of the **Rated MW** output, the voltage control system shall maintain the reactive power transfer at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) to 0 MVAr. For the avoidance of doubt the steady state tolerance allowed in CC.6.3.2(b) may be applied. In the case of **Gensets** comprising current source **DC Converter** technology or comprising **Power Park Modules** connected to the **Total System** by a current source **DC Converter** when operating at any power output the voltage control system shall maintain the reactive power transfer at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) to 0 MVAr. For the avoidance of doubt the steady state tolerance allowed in CC.6.3.2(b) may be applied.

(d) In the absence of any Mvar **Ancillary Service** instructions, the Mvar output of each **Genset** should be 0 Mvar immediately prior to **De-Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**, other than in the case of a rapid unplanned **De-Synchronisation** or in the case of a **Genset** comprising of **Non-Synchronous Generating Units**, **Power Park Modules** or **DC Converters** which is operating at less than 20% of its **Rated MW** output where the requirements of BC2.5.4 (b) part (ii) apply.

(e) a **Generator** should at all times operate its **CCGT Units** in accordance with the applicable **CCGT Module Matrix**;

(f) in the case of a **Range CCGT Module**, a **Generator** must operate that **CCGT Module** so that power is provided at the single **Grid Entry Point** identified in the data given pursuant to PC.A.3.2.1 or at the single **Grid Entry Point** to which **NGC** has agreed pursuant to BC1.4.2(f);

(g) in the event of the **System Frequency** being above 50.3Hz or below 49.7Hz, **BM Participants** must not commence any reasonably avoidable action to regulate the input or output of any **BM Unit** in a manner that could cause the **System Frequency** to deviate further from 50Hz without first using reasonable endeavours to discuss the proposed actions with **NGC**. **NGC** shall either agree to these changes in input or output or issue a **Bid-Offer Acceptance** in accordance with BC2.7 to delay the change.

(h) a **Generator** should at all times operate its **Power Park Units** in accordance with the applicable **Power Park Module Availability Matrix**.

BC2.5.5 Commencement or Termination of Participation in the **Balancing Mechanism**

BC2.5.5.1 In the event that a **BM Participant** in respect of a **BM Unit** with a **Demand Capacity** with a magnitude of less than 50MW in England and Wales or less than 5MW in Scotland or comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC2.2) and/or **CCGT Modules** and /or **Power Park Modules** at a **Small Power Station** notifies **NGC** at least 30 days in advance that from a specified **Operational Day** it will:

(a) no longer submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** no longer has to meet the requirements of BC2.5.1 nor the requirements of CC6.5.8(b) in relation to that **BM Unit**. Also, with effect from that **Operational Day**, any defaulted **Physical Notification** and defaulted **Bid-Offer Data** in relation to that **BM Unit** arising from the **Data Validation, Consistency and Defaulting Rules** will be disregarded and the provisions of BC2.5.2 will not apply;

(b) submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** will need to meet the requirements of BC2.5.1 and the requirements of CC6.5.8(b) in relation to that **BM Unit**.

BC2.5.5.2 In the event that a **BM Participant** in respect of a **BM Unit** with a **Demand Capacity** with a magnitude of 50MW or greater in England and Wales or 5MW or greater in Scotland or comprising **Generating Units** (as defined in the Glossary and Definitions and not limited by BC2.2) and/or **CCGT Modules** and /or **Power Park Modules** at a **Medium Power Station** or **Large Power Station** notifies **NGC** at least 30 days in advance that from a specified **Operational Day** it will:

(a) no longer submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** no longer has to meet the requirements of CC6.5.8(b) in relation to that **BM Unit**; Also, with effect from that **Operational Day**, any defaulted **Bid-Offer Data** in relation to that **BM Unit** arising from the **Data Validation, Consistency and Defaulting Rules** will be disregarded;

(b) submit **Bid-Offer Data** under BC1.4.2(d), then with effect from that **Operational Day** that **BM Participant** will need to meet the requirements of CC6.5.8(b) in relation to that **BM Unit**.

……..

BC2.7.5 Additional Action Required from **Generators**

(a) When complying with **Bid-Offer Acceptances** for a **CCGT Module** a **Generator** will operate its **CCGT Units** in accordance with the applicable **CCGT Module Matrix**.

(b) When complying with **Bid-Offer Acceptances** for a **CCGT Module** which is a **Range CCGT Module**, a **Generator** must operate that **CCGT Module** so that power is provided at the single **Grid Entry Point** identified in the data given pursuant to PC.A.3.2.1 or at the single **Grid Entry Point** to which **NGC** has agreed pursuant to BC1.4.2 (f).

(c) On receiving a new MW **Bid-Offer Acceptance**, no tap changing shall be carried out to change the Mvar output unless there is a new Mvar **Ancillary Service** instruction issued pursuant to BC2.8.

(d) When complying with **Bid-Offer Acceptances** for a **Power Park Module** a **Generator** will operate its **Power Park Units** in accordance with the applicable **Power Park Module Availability Matrix**.

……

BC2.9 EMERGENCY CIRCUMSTANCES

BC2.9.1 Emergency Actions

BC2.9.1.1 In certain circumstances (as determined by **NGC** in its reasonable opinion) it will be necessary, in order to preserve the integrity of the **GB Transmission System** and any synchronously connected **External System**, for **NGC** to issue **Emergency Instructions.** In such circumstances, it may be necessary to depart from normal **Balancing Mechanism** operation in accordance with BC2.7 in issuing **Bid-Offer Acceptances**. **BM Participants** must also comply with the requirements of **BC3**.

BC2.9.1.2 Examples of circumstances that may require the issue of **Emergency Instructions** include:-

(a) **Events** on the **GB Transmission System** or the **System** of another **User**; or

(b) the need to maintain adequate **System** and **Localised NRAPM** in accordance with BC2.9.4 below; or

(c) the need to maintain adequate frequency sensitive **Gensets** ~~**Generating Units** (as defined in the Glossary and Definitions and not limited by BC2.2)~~in accordance with BC2.9.5 below; or

(d) the need to implement **Demand Control** in accordance with OC6; or

(e) (i) the need to invoke the **Black Start** process or the **Re-Synchronisation of De-Synchronised Island** process in accordance with OC9; or

(ii) the need to request provision of a **Maximum Generation Service**.

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BC2.9.3 Examples of **Emergency Instructions**

BC2.9.3.1 In the case of a **BM Unit** or **Generating Unit**, **Emergency Instructions** may include an instruction for the **BM Unit** or the **Generating Unit** to operate in a way that is not consistent with the **Dynamic Parameters**, **QPNs** and/or **Export and Import Limits**.

BC2.9.3.2 In the case of a **Generator, Emergency Instructions** may include**:**

(a) an instruction to trip one or more **Gensets;** or

(b) an instruction to trip **Mills** or to **Part Load** a **Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2); or

(c) an instruction to **Part Load** a **CCGT Module** or **Power Park Module**; or

(d) an instruction for the operation of **CCGT Units** within a **CCGT Module** (on the basis of the information contained within the **CCGT Module Matrix**) when emergency circumstances prevail (as determined by **NGC** in **NGC's** reasonable opinion); or

(e) an instruction to generate outside normal parameters, as allowed for 4.2 of the **CUSC**; or

(f) an instruction for the operation of **Generating Units** within a **Cascade Hydro Scheme** (on the basis of the additional information supplied in relation to individual **Generating Units**) when emergency circumstances prevail (as determined by **NGC** in **NGC's** reasonable opinion~~).~~): or

(g) an instruction for the operation of a **Power Park Module** (on the basis of the information contained within the **Power Park Module Availability Matrix**) when emergency circumstances prevail (as determined by **NGC** in **NGC's** reasonable opinion).

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BC2.11 LIAISON WITH **GENERATORS** FOR RISK OF TRIP AND **AVR** TESTING

BC2.11.1 A **Generator** at the **Control Point** for any of its **Large Power Stations** may request **NGC's** agreement for one of the **Gensets** at that **Power Station** to be operated under a risk of trip. **NGC's** agreement will be dependent on the risk to the **GB Transmission System** that a trip of the **Genset** would constitute.

BC2.11.2 (a) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Synchronised Gensets** (excluding **Power Park Modules**) with:

(i) **AVRs** in constant terminal voltage mode with VAR limiters in service at all times. **AVR** constant **Reactive Power** or ~~p~~**Power** ~~f~~**Factor** mode should, if installed, be disabled; and

(ii) its generator step-up transformer tap changer selected to manual mode,

unless released from this obligation in respect of a particular **Genset** by **NGC**.

(b) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Power Park Modules** with a **Completion Date** before **1st January 2006** at unity power factor at the **Grid Entry Point** (or **User System Entry Point** if **Embedded).**

(c) Each **Generator** at the **Control Point** for any of its **Large Power Stations** will operate its **Power Park Modules** with a **Completion Date** on or after **1st January 2006** in voltage control mode at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**). Constant **Reactive Power** or **Power Factor** mode should, if installed, be disabled.

(~~b~~d) Where a ~~p~~**Power** ~~s~~**System** ~~s~~**Stabiliser** is fitted as part of ~~an~~ the excitation system or voltage control system of a **Genset**, it requires on-load commissioning which must be witnessed by **NGC**. Only when the performance of the ~~p~~**Power** ~~s~~**System** ~~s~~**Stabiliser** has been approved by **NGC** shall it be switched into service by a **Generator** and then it will be kept in service at all times unless otherwise agreed with **NGC**. Further reference is made to this in CC.6.3.8.

BC2.11.3 A **Generator** at the **Control Point** for any of its **Power Stations** may request **NGC's** agreement for one of its **Gensets** at that **Power Station** to be operated with the **AVR** in manual mode, or ~~p~~**Power** ~~s~~**System** ~~s~~**Stabiliser** switched out, or VAR limiter switched out. **NGC's** agreement will be dependent on the risk that would be imposed on the **GB Transmission System** and any **User System**. Provided that in any event a **Generator** may take such action as is reasonably necessary on safety grounds (relating to personnel or plant) .

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Appendix 3 – Submission of Revised Mvar Capability

BC2.A.3.1 For the purpose of submitting revised Mvar data the following terms shall apply:

Full Output: In the case of a **Synchronous Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) is t~~T~~he MW output ~~of a **Generating Unit**~~ measured at the generator stator terminals representing the LV equivalent of the **Registered Capacity** at the **Grid Entry Point**, and in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **DC Converter** or **Power Park Module** is the **Registered Capacity** at the **Grid Entry Point**.

Minimum Output: In the case of a **Synchronous Generating Unit** (as defined in the Glossary and Definitions and not limited by BC2.2) is t~~T~~he MW output ~~of a **Generating Unit**~~ measured at the generator stator terminals representing the LV equivalent of the **Minimum Generation** at the **Grid Entry Point**, and in the case of a **Non-Synchronous Generating Unit** (excluding **Power Park Units**), **DC Converter** or **Power Park Module** is the **Minimum Generation** at the **Grid Entry Point**.

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APPENDIX 3 - ANNEXURE 2

To: NGC Transmission Control Centre

From : [*Company Name & Location*]

REVISED Mvar DATA

NOTIFICATION TIME:

HRS MINS DD MM YY
. / /

GENERATING UNIT* /POWER PARK MODULE DC CONVERTER	

Start Time/Date (if not effective immediately)

REACTIVE POWER CAPABILITY AT SYNCHRONOUS GENERATING UNIT~~GENERATOR~~ STATOR TERMINAL (at rated terminal volts) **OR AT THE CONNECTION POINT FOR OTHER GENSETS AND DC CONVERTERS**

	MW	LEAD (Mvar)	LAG (Mvar)
AT **RATED MW**			
AT FULL OUTPUT (MW)			
AT MINIMUM OUTPUT (MW)			

GENERATING UNIT STEP-UP TRANSFORMER DATA, WHERE APPLICABLE

TAP CHANGE RANGE (+%,-%)	TAP NUMBER RANGE

OPTIONAL INFORMATION (for Ancillary Services use only) **-**
REACTIVE POWER CAPABILITY AT COMMERCIAL BOUNDARY (at rated stator terminal and nominal system volts)

	LEAD (Mvar)	LAG (Mvar)
AT **RATED MW**		

Predicted End Time/Date (to be confirmed by redeclaration)

Redeclaration made by (Signature) ____

Generating Unit has the meaning given in the Glossary and Definitions and is not limited by BC2.2

* For a CCGT, the redeclaration is for an individual CCGT unit and not the entire module.

< End of BC2 >

EXTRACTS FROM - BALANCING CODE NO.3

FREQUENCY CONTROL PROCESS

BC3.1 INTRODUCTION

BC3.1.1 **BC3** sets out the procedure for **NGC** to use in relation to **Users** to undertake **System Frequency** control. **System Frequency** will be controlled by response from **Gensets** (and **DC Converters** at **DC Converter Stations**) operating in **Limited Frequency Sensitive Mode** or **Frequency Sensitive Mode**, by the issuing of instructions to **Gensets** (and **DC Converters** at **DC Converter Stations**) and by control of **Demand**. The requirements for **Frequency** control are determined by the consequences and effectiveness of the **Balancing Mechanism**, and accordingly, **BC3** is complementary to **BC1** and **BC2**.

BC3.1.2 Inter-relationship with **Ancillary Services**

The provision of response (other than by operation in **Limited Frequency Sensitive Mode** or in accordance with BC3.7.1(c)) in order to contribute towards **Frequency** control, as described in **BC3**, by **Generators** or **DC Converter Station** owners will be an **Ancillary Service**. **Ancillary Services** are divided into three categories, **System Ancillary Services** Parts 1 and 2 and **Commercial Ancillary Services**. **System Ancillary Services**, Parts 1 and 2, are those **Ancillary Services** listed in CC.8.1; those in Part 1 of CC.8.1 are those for which the **Connection Conditions** require the capability as a condition of connection and those in Part 2 are those which may be agreed to be provided by **Users** and which can only be utilised by **NGC** if so agreed. **Commercial Ancillary Services** like those **System Ancillary Services** set out in Part 2 of CC.8.1, may be agreed to be provided by **Users** and which can only be utilised by **NGC** if so agreed.

BC3.1.3 The provision of **Frequency** control services, if any, from an **External System** via a **DC Converter Station** will be provided for in the **Ancillary Services Agreement** and/or **Bilateral Agreement** with the **DC Converter Station** owner and/or any other relevant agreements with the relevant EISO.

BC3.2 OBJECTIVE

The procedure for **NGC** to direct **System Frequency** control is intended to enable (as far as possible) **NGC** to meet the statutory requirements of **System Frequency** control.

BC3.3 SCOPE

BC3 applies to **NGC** and to **Users**, which in this BC3 means:-

(a) **Generators** with regard to their **Large Power Stations** (except those **Large Power Stations** comprising of **Power Park Modules** in **SHETL's Transmission Area** with a **Registered Capacity** less than 30MW),

(b) **Network Operators,**

(c) **DC Converter Station** owners

~~(c)~~(d) other providers of **Ancillary Services**, and

(e) **Externally Interconnected System Operators**.

BC3.4 MANAGING **SYSTEM FREQUENCY**

BC3.4.1 Statutory Requirements

When **NGC** determines it is necessary (by having monitored the **System Frequency**), it will, as part of the procedure set out in **BC2**, issue instructions (including instructions for **Commercial Ancillary Services**) in order to seek to regulate **System Frequency** to meet the statutory requirements of **Frequency** control. **Gensets** (except those comprising of a **Power Park Module** in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** less than 30MW and those comprising of a **Power Park Module** in Scotland with a **Completion Date** before 1 July 2004) and **DC Converters** at **DC Converter Stations** when transferring **Active Power** to the **Total System**, operating in **Frequency Sensitive Mode** will be instructed by **NGC** to operate taking due account of the **Target Frequency** notified by **NGC**.

BC3.4.2 **Target Frequency**

NGC will give 15 minutes notice of variation in **Target Frequency**.

BC3.4.3 Electric Time

NGC will endeavour (in so far as it is able) to control electric clock time to within plus or minus 10 seconds by specifying changes to **Target Frequency,** by accepting bids and offers in the **Balancing Mechanism**. Errors greater than plus or minus 10 seconds may be temporarily accepted at **NGC 's** reasonable discretion.

BC3.5 RESPONSE FROM **GENSETS** (AND **DC CONVERTERS** AT **DC CONVERTER STATIONS** WHEN TRANSFERRING **ACTIVE POWER** TO THE **TOTAL SYSTEM**)

BC3.5.1 Capability

Each **Genset** (except those comprising of **Power Park Modules** in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** less than 30MW and those comprising of **Power Park Modules** in Scotland with a **Completion Date** before 1 July 2004) and each **DC Converter** at a **DC Converter Station** must at all times have the capability to operate automatically so as to provide response to changes in **Frequency** in accordance with the requirements of CC.6.3.7 in order to contribute to containing and correcting the **System Frequency** within the statutory requirements of **Frequency** control. For **DC Converters** at **DC Converter Stations, BC.3.1.3** also applies. In addition each **Genset** (and each **DC Converter** at a **DC Converter Station**) must at all times have the capability to operate in a **Limited Frequency Sensitive Mode** by operating so as to provide **Limited High Frequency Response**.

BC3.5.2 **Limited Frequency Sensitive Mode**

Each **Synchronised Genset** producing **Active Power** (and each **DC Converter** at a **DC Converter Station**) must operate at all times in a **Limited Frequency Sensitive Mode** (unless instructed in accordance with BC3.5.4 below to operate in **Frequency Sensitive Mode**). Operation in **Limited Frequency Sensitive Mode** must achieve the capability requirement described in CC.6.3.3 for **System Frequencies** up to 50.4Hz and shall be deemed not to be in contravention of CC.6.3.7.

BC3.5.3 (a) **Existing Gas Cooled Reactor Plant**

NGC will permit **Existing Gas Cooled Reactor Plant** other than **Frequency Sensitive AGR Units** to operate in **Limited Frequency Sensitive Mode** at all times.

(b) **Power Park Modules** in operation before 1 January 2006

NGC will permit **Power Park Modules** in operation before 1 January 2006 to operate in **Limited Frequency Sensitive Mode** at all times. For the avoidance of doubt **Power Park Modules** in England and Wales with a **Completion Date** on or after 1 January 2006 and **Power Park Modules** in operation in Scotland after 1 January 2006 with a **Completion Date** after 1 July 2004 and in a **Power Station** with a **Registered Capacity** of 30MW and greater will be required to operate in both **Limited Frequency Sensitive Mode** and **Frequency Sensitive Mode** of operation depending on **System** conditions.

BC3.5.4 **Frequency Sensitive Mode**

(a) **NGC** may issue an instruction to a **Genset** (or **DC Converter** at a **DC Converter Station** if agreed as described in BC.3.1.3) to operate so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response** (in the combinations agreed in the relevant **Ancillary Services Agreement**). When so instructed, the **Genset** or **DC Converter** at a **DC Converter Station** must operate in accordance with the instruction and will no longer be operating in **Limited Frequency Sensitive Mode**, but by being so instructed will be operating in **Frequency Sensitive Mode**.

(b) **Frequency Sensitive Mode** is the generic description for a **Genset** (or **DC Converter** at a **DC Converter Station**) operating in accordance with an instruction to operate so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response** (in the combinations agreed in the relevant **Ancillary Services Agreement**).

(c) The magnitude of the response in each of those categories instructed will be in accordance with the relevant **Ancillary Services Agreement** with the **Generator** or **DC Converter Station** owner.

(d) Such instruction will continue until countermanded by **NGC** or until;

(i) -the **Genset** is **De-Synchronised**; or,

(ii) the **DC Converter** ceases to transfer **Active Power** to or from the **Total System** subject to the conditions of any relevant agreement relating to the operation of the **DC Converter Station**,

whichever is the first to occur.

(e) **NGC** will not so instruct **Generators** in respect of **Existing Gas Cooled Reactor Plant** other than **Frequency Sensitive AGR Units**.

(f) **NGC** will not so instruct **Generators** in respect of **Power Park Modules**:

(i) in Scotland with a **Completion Date** before 1 July 2004; or,

(ii) in **SHETL's Transmission Area** in a **Power Station** with a **Registered Capacity** of less than 30MW.

(iii) in England and Wales with a **Completion Date** before 1 January 2006

BC3.5.5 **System Frequency** Induced Change

A **System Frequency** induced change in the **Active Power** output of a **Genset** (or **DC Converter** at a **DC Converter Station**) which assists recovery to **Target Frequency** must not be countermanded by a **Generator** or **DC Converter Station** owner except where it is done purely on safety grounds (relating to either personnel or plant) or, where necessary, to ensure the integrity of the **Power Station** or **DC Converter Station**.

BC3.6 RESPONSE TO **LOW FREQUENCY**

BC3.6.1 **Low Frequency Relay** Initiated Response from **Gensets** and **DC Converters** at **DC Converter Stations**

(a) **NGC** may utilise **Gensets** (and **DC Converters** at **DC Converter Stations**) with the capability of **Low Frequency Relay** initiated response as:

(i) synchronisation and generation from standstill;

(ii) generation from zero generated output;

(iii) increase in generated output

(iv) increase in **DC Converter** output to the **Total System** (if so agreed as described in BC3.1.3);

(v) decrease in **DC Converter** input from the **Total System** (if so agreed as described in BC3.1.3);

in establishing its requirements for **Operating Reserve**.

(b) (i) **NGC** will specify within the range agreed with **Generators** and/or **EISOs** and/or **DC Converter Station** owners (if so agreed as described in BC3.1.3), **Low Frequency Relay** settings to be applied to ~~the~~ **Gensets** or **DC Converters** at **DC Converter Stations** pursuant to BC3.6.1 (a) and instruct the **Low Frequency Relay** initiated response placed in and out of service.

(ii) **Generators** and/or **EISOs** and/or **DC Converter Station** owners (if so agreed as described in BC3.1.3) will comply with **NGC** instructions for **Low Frequency Relay** settings and **Low Frequency Relay** initiated response to be placed in or out of service. **Generators** or **DC Converter Station** owners or EISOs may not alter such **Low Frequency Relay** settings or take **Low Frequency Relay** initiated response out of service without **NGC's** agreement (such agreement not to be unreasonably withheld or delayed), except for safety reasons.

BC3.6.2 **<u>Low Frequency Relay</u>** <u>Initiated Response from</u> **<u>Demand</u>** <u>and other</u> **<u>Demand</u>** <u>modification arrangements(which may include a **DC Converter Station** when importing **Active Power** from the **Total System**)</u>

(a) **NGC** may, pursuant to an **Ancillary Services Agreement**, utilise **Demand** with the capability of **Low Frequency Relay** initiated **Demand** reduction in establishing its requirements for **Frequency Control**.

(b) (i) **NGC** will specify within the range agreed the **Low Frequency Relay** settings to be applied pursuant to BC3.6.2 (a), the amount of **Demand** reduction to be available and will instruct the **Low Frequency Relay** initiated response to be placed in or out of service.

(ii) **Users** will comply with **NGC** instructions for **Low Frequency Relay** settings and **Low Frequency Relay** initiated **Demand** reduction to be placed in or out of service. **Users** may not alter such **Low Frequency Relay** settings or take **Low Frequency Relay** initiated response out of service without **NGC 's** agreement, except for safety reasons.

(iii) In the case of any such **Demand** which is **Embedded**, **NGC** will notify the relevant **Network Operator** of the location of the **Demand**, the amount of **Demand** reduction to be available, and the **Low Frequency Relay** settings.

(c) **NGC** may also utilise other **Demand** modification arrangements pursuant to an agreement for **Ancillary Services**, in order to contribute towards **Operating Reserve.**

BC3.7 <u>RESPONSE TO **HIGH FREQUENCY** REQUIRED FROM **SYNCHRONISED GENSETS** (AND **DC CONVERTERS** AT **DC CONVERTER STATIONS** WHEN TRANSFERRING **ACTIVE POWER** TO THE **TOTAL SYSTEM**)</u>

BC3.7.1 <u>Plant in **Frequency Sensitive Mode** instructed to provide **High Frequency Response**</u>

(a) Each **Synchronised Genset** <u>(or each **DC Converter** at a **DC Converter Station**)</u>in respect of which the **Generator** <u>or **DC Converter Station** owner and/or **EISO**</u> has been instructed to operate so as to provide **High Frequency Response**, which is producing **Active Power** and which is operating above <u>the</u> **Designed Minimum Operating Level**, is required to reduce **Active Power** output in response to an increase in **System Frequency** above the **Target Frequency** (or such other level of **Frequency** as may have been agreed in an **Ancillary Services Agreement**). The **Target Frequency** is normally 50.00 Hz except where modified as specified under BC3.4.2.

(b) (i) The rate of change of **Active Power** output with respect to **Frequency** up to 50.5 Hz shall be in accordance with the provisions of the relevant **Ancillary Services Agreement** with each **Generator** <u>or **DC Converter Station** owner</u>. If more than one rate is provided for in the **Ancillary Services Agreement** **NGC** will instruct the rate when the instruction to operate to provide **High Frequency Response** is given.

(ii) The reduction in **Active Power** output by the amount provided for in the relevant **Ancillary Services Agreement** must be fully achieved within 10 seconds of the time of the **Frequency** increase and must be sustained at no lesser reduction thereafter.

(iii) It is accepted that the reduction in **Active Power** output may not be to below the **Designed Minimum Operating Level.**

(c) In addition to the **High Frequency Response** provided, the **Genset** (or **DC Converter** at a **DC Converter Station**)must continue to reduce **Active Power** output in response to an increase in **System Frequency** to 50.5 Hz or above at a minimum rate of 2 per cent of output per 0.1 Hz deviation of **System Frequency** above that level, such reduction to be achieved within five minutes of the rise to or above 50.5 Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**.

BC3.7.2 Plant in **Limited Frequency Sensitive Mode**

(a) Each **Synchronised Genset** **(or DC Converter** at a **DC Converter Station)** operating in a **Limited Frequency Sensitive Mode** which is producing **Active Power** is also required to reduce **Active Power** output in response to **System Frequency** when this rises above 50.4 Hz. In the case of **DC Converters** at **DC Converter Stations,** the provisions of **BC.3.7.7** are also applicable**.** For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as "**Limited High Frequency Response**".

(b) (i) The rate of change of **Active Power** output must be at a minimum rate of 2 per cent of output per 0.1 Hz deviation of **System Frequency** above 50.4 Hz.

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the **Frequency** control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz.

(iv) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Genset** (or **DC Converter** at a **DC Converter Station**) output control devices other than the **Frequency** control devices (or speed governors must be achieved within 3 minutes from the time of the **Frequency** increase above 50.4 Hz.

(v) Any further residue of the proportional reduction which results from non-automatic action initiated by the **Generator** or **DC Converter Station** owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the **Frequency** increase above 50.4 Hz.

(c) Each **Genset** (or **DC Converter** at a **DC Converter Station**) which is providing **Limited High Frequency Response** in accordance with this BC3.7.2 must continue to provide it until the **Frequency** has returned to or below 50.4 Hz or until otherwise instructed by **NGC**.

BC3.7.3 Plant operation to below **Minimum Generation**

(a) As stated in CC.A.3.2, steady state operation below **Minimum Generation** is not expected but if **System** operating conditions cause operation below **Minimum Generation** which give rise to operational difficulties for the **Genset** (or **DC Converter** at a **DC Converter Station**) then **NGC** should not, upon request, unreasonably withhold issuing a **Bid-Offer Acceptance** to return the **Generating Unit** or **CCGT Module** or **Power Park Module** or **DC Converter** to an output not less than **Minimum Generation**. In the case of a **DC Converter** not participating in the **Balancing Mechanism**, then **NGC** will, upon request, attempt to return the **DC Converter** to an output not less than **Minimum Generation** or to zero transfer or to reverse the transfer of **Active Power**.

(b) It is possible that a **Synchronised Gensets** (or a **DC Converter** at a **DC Converter Station**) which ~~have~~ responded as required under BC3.7.1 or BC3.7.2 to an excess of **System Frequency**, as therein described, will (if the output reduction is large or if the **Genset** (or a **DC Converter** at a **DC Converter Station**) output has reduced to below the **Designed Minimum Operating Level**) trip after a time.

(c) All reasonable efforts should in the event be made by the **Generator** or **DC Converter Station** owner to avoid such tripping, provided that the **System Frequency** is below 52Hz.

(d) If the **System Frequency** is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the **Generator** or **DC Converter Station** owner is required to take action to protect the **Generating Units**, **Power Park Modules** or **DC Converters** as specified in CC.6.3.13.

(e) In the event of the **System Frequency** becoming stable above 50.5Hz, after all **Genset** and **DC Converter** action as specified in BC3.7.1 and BC3.7.2 has taken place, **NGC** will issue appropriate **Bid-Offer Acceptances** and/or **Ancillary Service** instructions, which may include **Emergency Instructions** under **BC2** to trip **Gensets** (or, in the case of **DC Converters** at **DC Converter Stations**, to stop or reverse the transfer of **Active Power**) so that the **Frequency** returns to below 50.5Hz and ultimately to **Target Frequency**.

(f) If the **System Frequency** has become stable above 52 Hz, after all **Genset** and **DC Converter** action as specified in BC3.7.1 and BC3.7.2 has taken place, **NGC** will issue **Emergency Instructions** under **BC2** to trip appropriate **Gensets**(or in the case of **DC Converters** at **DC Converter Stations** to stop or reverse the transfer of **Active Power**) to bring the **System Frequency** to below 52Hz and follow this with appropriate **Bid-Offer Acceptances** or **Ancillary Service** instructions or further **Emergency Instructions** under **BC2** to return the **System Frequency** to below 50.5 Hz and ultimately to **Target Frequency**.

BC3.7.4 The **Generator** or **DC Converter Station** owner will not be in breach of any of the provisions of BC2 by following the provisions of BC3.7.1, BC3.7.2 or BC3.7.3.

BC3.7.5 Information update to **NGC**

In order that **NGC** can deal with the emergency conditions effectively, it needs as much up to date information as possible and accordingly **NGC** must be informed of the action taken in accordance with BC3.7.1(c) and BC3.7.2 as soon as possible and in any event within 7 minutes of the rise in **System Frequency**, directly by telephone from the **Control Point** for the **Power Station** or **DC Converter Station**.

BC3.7.6 (a) **Existing Gas Cooled Reactor Plant**

For the avoidance of doubt, **Generating Units** within **Existing Gas Cooled Reactor Plant** are required to comply with the applicable provisions of this BC3.7 (which, for the avoidance of doubt, other than for **Frequency Sensitive AGR Units**, do not include BC3.7.1).

(b) **Power Park Modules** in operation before 1 January 2006.

For the avoidance of doubt, **Power Park Modules** in operation (irrespective of their **Completion Dates**) before 1 January 2006 are required to comply with the applicable provisions of this BC3.7 (which, for the avoidance of doubt do not include BC3.7.1).

BC3.7.7 **Externally Interconnected System Operators**

NGC will use reasonable endeavours to ensure that, if **System Frequency** rises above 50.4Hz, and an **Externally Interconnected System Operator** (in its role as operator of the **External System**) is transferring power into the **GB Transmission System** from its **External System**, the amount of power transferred in to the **GB Transmission System** from the **System** of that **Externally Interconnected System Operator** is reduced at a rate equivalent to (or greater than) that which applies for **Synchronised Gensets** operating in **Limited Frequency Sensitive Mode** which are producing **Active Power**. This will be done either by utilising existing arrangements which are designed to achieve this, or by issuing **Emergency Instructions** under **BC2**.

< End of BC3 >

EXTRACTS FROM DATA REGISTRATION CODE

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DRC.3 SCOPE

DRC.3.1 The **DRC** applies to **NGC** and to **Users**, which in this **DRC** means:-

(a) **Generators**;

(b) **Network Operators**;

(c) **DC Converter Station** owners

(~~c~~d) **Suppliers**;

(~~d~~e) **Non-Embedded Customers** (including, for the avoidance of doubt, a **Pumped Storage Generator** in that capacity);

(~~e~~f) **Externally Interconnected System Operators**;

(g) **Interconnector Users;** and

(h) **BM Participants**.

DRC.6 **DATA TO BE REGISTERED**

DRC.6.1 Schedules 1 to 15 attached cover the following data areas.

DRC.6.1.1 SCHEDULE 1 - **GENERATING UNIT** (OR **CCGT Module**), **POWER PARK MODULE** and **DC CONVERTER** TECHNICAL DATA.

Comprising **Generating Unit** (and **CCGT Module**), **Power Park Module** and **DC Converter** fixed electrical parameters.

DRC.6.1.2 SCHEDULE 2 - **GENERATION PLANNING PARAMETERS**

Comprising the **Genset** parameters required for **Operational Planning** studies.

DRC.6.1.3 SCHEDULE 3 - **LARGE POWER STATION** OUTAGE PROGRAMMES, OUTPUT USABLE AND INFLEXIBILITY INFORMATION.

Comprising generation outage planning, **Output Usable** and inflexibility information at timescales down to the daily **BM Unit Data** submission.

DRC.6.1.4 SCHEDULE 4 - **LARGE POWER STATION DROOP** AND RESPONSE DATA.

Comprising data on governor ~~d~~**Droop** settings and **Primary**, **Secondary** and **High Frequency Response** data for **Large Power Stations**.

DRC.6.1.5 SCHEDULE 5 - **USER'S SYSTEM** DATA.

Comprising electrical parameters relating to **Plant** and **Apparatus** connected to the **GB Transmission System**.

DRC.6.1.6 SCHEDULE 6 - **USERS** OUTAGE INFORMATION.

Comprising the information required by **NGC** for outages on the **Users System**, including outages at **Power Stations** other than outages of **Gensets**

DRC.6.1.7 SCHEDULE 7 - LOAD CHARACTERISTICS.

Comprising the estimated parameters of load groups in respect of, for example, harmonic content and response to frequency.

DRC.6.1.8 SCHEDULE 8 - **BM UNIT** DATA.

DRC.6.1.9 SCHEDULE 9 - DATA SUPPLIED BY **NGC** TO **USERS**.

DRC.6.1.10 SCHEDULE 10 - **DEMAND** PROFILES AND **ACTIVE ENERGY** DATA

Comprising information relating to the **Network Operators'** and **Non-Embedded Customers'** total **Demand** and **Active Energy** taken from the **GB Transmission System**

DRC.6.1.11 SCHEDULE 11 - **CONNECTION POINT** DATA

Comprising information relating to **Demand**, demand transfer capability and a summary of the **Small Power Station, Medium Power Station** and **Customer** generation connected to the **Connection Point**

DRC.6.1.12 SCHEDULE 12 - **DEMAND CONTROL** DATA

Comprising information related to **Demand Control**

DRC.6.1.13 SCHEDULE 13 - **FAULT INFEED DATA**

Comprising information relating to the Short Circuit contribution to the **GB Transmission System** from **Users** other than **Generators** and **DC Converter Station** owners.

DRC.6.1.14 SCHEDULE 14 - **FAULT INFEED DATA**

Comprising information relating to the Short Circuit contribution to the **GB Transmission System** from **Generators** and **DC Converter Station** owners.

DRC.6.1.15 SCHEDULE 15 – **MOTHBALLED GENERATING UNIT, MOTHBALLED POWER PARK MODULE, MOTHBALLED DC CONVERTERS AT A DC CONVERTER STATION** AND ALTERNATIVE FUEL DATA

Comprising information relating to estimated return to service times for **Mothballed Generating Units, Mothballed Power Park Modules** and **Mothballed DC Converters at a DC Converter Station** and the capability of gas-fired **Generating Units** to operate using alternative fuels.

DRC.6.2 The **Schedules** applicable to each class of **User** are as follows:

Generators with **Large Power Stations**	Sched 1, 2, 3, 4, 9, 14, 15
Generators with **Medium Power Stations** (See note 2)	Sched 1, 9, 14, 15
Generators with **Small Power Stations** directly connected to the **GB Transmission System**	Sched 1, 6, 14, 15
All **Users** connected directly to **GB Transmission System**	Sched 5, 6, 9
All **Users** connected directly to the **GB Transmission System** other than **Generators**	Sched 10,11,13
All **Users** connected directly to **GB Transmission System** with **Demand**	Sched 7, 9
A **Pumped Storage Generator, Externally Interconnected System Operator** and **Interconnector Users**	Sched12 (as marked)
All **Suppliers**	Sched 12
All **Network Operators**	Sched 12
All **BM Participants**	Sched 8
All **DC Converter Station** owners	Sched 1, 4, 9, 14, 15

Notes:

1. **Network Operators** must provide data relating to **Small Power Stations** and/or **Customer Generating Plant Embedded** in their **Systems** when such data is requested by **NGC** pursuant to PC.A.3.1.4 or PC.A.5.1.4.

2. The data in schedules 1, 14 and 15 need not be supplied in relation to **Medium Power Stations** connected at a voltage level below the voltage level of the **Subtransmission System** except in connection with a **CUSC Contract** or unless specifically requested by **NGC**.

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DATA DESCRIPTION	UNITS	DATA CAT.	POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
Power Park Module Rated MVA	MVA	**SPD+**							
Power Park Module Rated MW	MW	**SPD+**							
*Performance Chart of a **Power Park Module** at the connection point		**SPD**	(see **OC2** for specification)						
***Output Usable** (on a monthly basis)	MW	**SPD**	(except in relation to **CCGT Modules** when required on a unit basis under the **Grid Code**, this data item may be supplied under Schedule 3)						
Number & Type of **Power Park Units** within each **Power Park Module**									
Power Park Unit Model - A validated mathematical model in accordance with PC.5.4.2 (a)	Transfer function block diagram and algebraic equations, simulation and measured test results	**DPD**							
Power Park Unit Data (where applicable)									
Rated MVA	MVA	**SPD+**							
Rated MW	MW	**SPD+**							
Rated terminal voltage	V	**SPD+**							
Inertia constant at synchronous speed	MW secs /MVA	**SPD+**							
Stator Resistance.	% on MVA	**DPD**							
Stator Reactance.	% on MVA	**SPD+**							
Magnetising Reactance	% on MVA	**SPD+**							
Rotor Resistance (at starting).	% on MVA	**DSPD+**							
Rotor Resistance (at rated running)	% on MVA	**SPD+**							
Rotor Reactance (at starting).	% on MVA	**DPD+**							
Rotor Reactance (at rated running)	% on MVA	**SPD**							
Inertia constant of the wind turbine rotor	MW secs /MVA	**DPD**							
Inertia constant of the generator rotor	MW secs /MVA	**DPD**							
Shaft stiffness	Nm / electrical radian	**DPD**							

DATA DESCRIPTION	UNITS	DATA CAT.	POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
Minimum generator rotor speed ~~range~~ (Doubly Fed Induction Generators)	RPM	**SPD+**							
Maximum generator rotor speed ~~range~~ (Doubly Fed Induction Generators)	RPM	**SPD+**							
The optimum generator rotor speed versus wind speed	tabular format	**DPD**							
Power Converter Rating (Doubly Fed Induction Generators)	MVA	**SPD+**							
The rotor power coefficient (C_p) versus tip speed ratio (λ) curves for a range of blade angles (where applicable)	Diagram + tabular format	**DPD**							
The electrical power output versus generator rotor speed for a range of wind speeds over the entire operating range of the **Power Park Unit**.	Diagram + tabular format	**DPD**							
The blade angle versus wind speed curve	Diagram + tabular format	**DPD**							
The electrical power output versus wind speed over the entire operating range of **the Power Park Unit**.	Diagram + tabular format	**DPD**							
Transfer function block diagram, parameters and description of the operation of the power electronic converter (where applicable).	Diagram	**DPD**							
For a **Power Park Unit** consisting of a synchronous machine in combination with a back to back **DC Converter**, or for a **Power Park Unit** not driven by a wind turbine, the data to be supplied shall be agreed with NGC in accordance with PC.A.7.									

DATA DESCRIPTION	UNITS	DATA CAT.	**POWER PARK UNIT** (OR **POWER PARK MODULE**, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
Torque / Speed and blade angle control systems and parameters For the **Power Park Unit**, details of the torque / speed controller and blade angle controller in the case of a wind turbine and power limitation functions (where applicable) described in block diagram form showing transfer functions and parameters of individual elements	Diagram	**DPD**							
Voltage/**Reactive Power**/**Power Factor** control system parameters For the **Power Park Unit** and **Power Park Module** details of **Voltage/Reactive Power**/**Power Factor** controller (and **PSS** if fitted) described in block diagram form including parameters showing transfer functions of individual elements.	Diagram	**DPD**							
Frequency control system parameters For the **Power Park Unit** and **Power Park Module** details of the **Ffrequency** controller described in block diagram form showing transfer functions and parameters of individual elements.	Diagram	**DPD**							
As an alternative to PC.A.5.4.2 (a), (b), (c), (d), (e) and (f), is the submission of a single complete model that consists of the full information required under PC.A.5.4.2 (a), (b), (c), (d) (e) and (f) provided that all the information required under PC.A.5.4.2 (a), b), (c), (d), (e) and (f) individually is clearly identifiable.	Diagram	**DPD**							
Harmonic Assessment Information (as defined in IEC 61400-21 (2001)) for each **Power Park Unit**:-									
Flicker coefficient for continuous operation		**DPD**							
Flicker step factor		**DPD**							
Number of switching operations in a 10 minute window		**DPD**							
Number of switching operations in a 2 hour window		**DPD**							
Voltage change factor		**DPD**							
Current Injection at each harmonic for each **Power Park Unit** and for each **Power Park Module**	Tabular format	**DPD**							

DC CONVERTER STATION TECHNICAL DATA

DC CONVERTER STATION NAME ____________________ DATE: __________

Data Description	Units	Data Category	**DC Converter Station** Data
DC CONVERTER STATION DEMANDS:			
Demand supplied through **Station Transformers** associated with the **DC Converter Station [PC.A.4.1]**			
- **Demand** with all **DC Converters** operating at **Rated MW** import.	MW Mvar	**DPD** **DPD**	
- **Demand** with all **DC Converters** operating at **Rated MW** export.	MW Mvar	**DPD** **DPD**	
Additional **Demand** associated with the **DC Converter Station** supplied through the **GB Transmission System. [PC.A.4.1]**			
- The maximum **Demand** that could occur.	MW Mvar	**DPD** **DPD**	
- **Demand** at specified time of annual peak half hour of **NGC Demand** at **Annual ACS Conditions.**	MW Mvar	**DPD** **DPD**	
- **Demand** at specified time of annual minimum half-hour of **NGC Demand.**	MW Mvar	**DPD** **DPD**	
DC CONVERTER STATION DATA			
Number of poles, i.e. number of **DC Converters**	Text	**SPD+**	
Pole arrangement (e.g. monopole or bipole)	Text	**SPD+**	
Details of each viable operating configuration			
Configuration 1 Configuration 2 Configuration 3 Configuration 4 Configuration 5 Configuration 6	Diagram Diagram Diagram Diagram Diagram Diagram	**SPD+**	
Remote ac connection arrangement	Diagram	**SPD**	

Data Description	Units	Data Category	Operating Configuration					
			1	2	3	4	5	6
DC CONVERTER STATION DATA								
DC Converter Type (e.g. current or Voltage source)	Text	**SPD**						
Point of connection to the **NGC Transmission System** (or the **Total System** if embedded) of the **DC Converter Station** configuration in terms of geographical and electrical location and system voltage	Text	**SPD**						
If the busbars at the **Connection Point** are normally run in separate sections identify the section to which the **DC Converter Station** configuration is connected	Section Number	**SPD**						
Rated MW import per pole **[PC.A.3.3.1]**	MW	**SPD+**						
Rated MW export per pole **[PC.A.3.3.1]**	MW	**SPD+**						
ACTIVE POWER TRANSFER CAPABILITY (PC.A.3.2.2)								
Registered Capacity	MW	**SPD**						
Registered Import Capacity	MW	**SPD**						
Minimum Generation	MW	**SPD**						
Minimum Import Capacity	MW	**SPD**						
Import MW available in excess of **Registered Import Capacity.**	MW	**SPD**						
Time duration for which MW in excess of **Registered Import Capacity** is available	Min	**SPD**						
Export MW available in excess of **Registered Capacity.**	MW	**SPD**						
Time duration for which MW in excess of **Registered Capacity** is available	Min	**SPD**						
DC CONVERTER TRANSFORMER **[PC.A.5.4.3.1**								
Rated MVA	MVA	**DPD**						
Winding arrangement		**DPD**						
Nominal primary voltage	KV	**DPD**						
Nominal secondary (converter-side) voltage(s)	KV							
Positive sequence reactance								
Maximum tap	% on MVA	**DPD**						
Nominal tap	% on MVA	**DPD**						
Minimum tap	% on MVA	**DPD**						
Positive sequence resistance								
Maximum tap	% on MVA	**DPD**						
Nominal tap	% on MVA	**DPD**						
Minimum tap	% on MVA	**DPD**						
Zero phase sequence reactance	% on MVA	**DPD**						
Tap change range	+% / -%	**DPD**						
Number of steps		**DPD**						

Data Description	Units	Data Category	Operating configuration					
			1	2	3	4	5	6
DC NETWORK [PC.A.5.4.3.1 (c)]								
Rated DC voltage per pole	KV	**DPD**						
Rated DC current per pole	A	**DPD**						
Details of the **DC Network** described in diagram form including resistance, inductance and capacitance of all DC cables and/or DC lines. Details of any line reactors (including line reactor resistance), line capacitors, DC filters, earthing electrodes and other conductors that form part of the **DC Network** should be shown.	Diagram	**DPD**						
DC CONVERTER STATION AC HARMONIC FILTER AND REACTIVE COMPENSATION EQUIPMENT **[PC.A.5.4.3.1 (d)]**								
For all switched reactive compensation equipment	Diagram	**SPD**						
Total number of AC filter banks	Text	**SPD**						
Diagram of filter connections	Diagram	**SPD**						
Type of equipment (e.g. fixed or variable)	Text	**SPD**						
Capacitive rating; or	Mvar	**DPD**						
Inductive rating; or	Mvar	**DPD**						
Operating range	Mvar	**DPD**						
Reactive Power capability as a function of various MW transfer levels	Table	**DPD**						

Data Description	Units	Data Category	Operating configuration 1	2	3	4	5	6
CONTROL SYSTEMS **[PC.A.5.4.3.2]**								
Static V_{DC} – P_{DC} (DC voltage – DC power) or Static V_{DC} – I_{DC} (DC voltage – DC current) characteristic (as appropriate) when operating as		**DPD**						
–Rectifier	Diagram	**DPD**						
–Inverter	Diagram							
Details of rectifier mode control system, in block diagram form together with parameters showing transfer functions of individual elements.	Diagram	**DPD**						
Details of inverter mode control system, in block diagram form showing transfer functions of individual elements including parameters.	Diagram	**DPD**						
Details of converter transformer tap changer control system in block diagram form showing transfer functions of individual elements including parameters. (Only required for DC converters connected to the **GB Transmission System**.)	Diagram	**DPD**						
Details of AC filter and reactive compensation equipment control systems in block diagram form showing transfer functions of individual elements including parameters. (Only required for DC converters connected to the **GB Transmission System**.)	Diagram	**DPD**						
Details of any **Frequency** and/or load control systems in block diagram form showing transfer functions of individual elements including parameters.	Diagram	**DPD**						
Details of any large or small signal modulating controls, such as power oscillation damping controls or sub-synchronous oscillation damping controls, that have not been submitted as part of the above control system data.	Diagram	**DPD**						
Transfer block diagram representation of the **Reactive Power** control at converter ends for a voltage source converter.	Diagram	**DPD**						
LOADING PARAMETERS **[PC.A.5.4.3.3]**								
MW Export								
Nominal loading rate	MW/s	**DPD**						
Maximum (emergency) loading rate	MW/s	**DPD**						
MW Import								
Nominal loading rate	MW/s	**DPD**						
Maximum (emergency) loading rate	MW/s	**DPD**						
Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.	s	**DPD**						
Maximum recovery time, to 90% of pre-fault loading, following a transient **DC Network** fault.	s	**DPD**						

GENERATION PLANNING PARAMETERS

This schedule contains the **Genset Generation Planning Parameters** required by **NGC** to facilitate studies in **Operational Planning** timescales.

For a **Generating Unit** (other than a **Power Park Unit**) at a **Large Power Station** the information is to be submitted on a unit basis and for a **CCGT Module** or **Power Park Module** at a **Large Power Station** the information is to be submitted on a module basis, unless otherwise stated.

Where references to **CCGT Modules** or **Power Park Modules** at a **Large Power Station** are made, the columns "G1" etc should be amended to read "M1" etc, as appropriate.

Power Station: ___________________________

Generation Planning Parameters

DATA DESCRIPTION	UNITS	DATA CAT.	**GENSET** OR STATION DATA						
			G1	G2	G3	G4	G5	G6	STN
OUTPUT CAPABILITY									
Registered Capacity on a station and unit basis (on a station and module basis in the case of a **CCGT Module** or **Power Park Module** at a **Large Power Station)**	MW	**SPD**							
Minimum Generation (on a module basis in the case of a **CCGT Module** or **Power Park Module** at a **Large Power Station)**	MW	**SPD**							
MW available from **Generating Units** or **Power Park Module** in excess of **Registered Capacity**	MW	**SPD**							
REGIME UNAVAILABILITY									
These data blocks are provided to allow fixed periods of unavailability to be registered.									
Expected Running Regime. Is **Power Station** normally available for full output 24 hours per day, 7 days per week? If No please provide details of unavailability below.		**SPD**							
Earliest **Synchronising** time:									
Monday	hr/min	**OC2**							-
Tuesday – Friday	hr/min	**OC2**							-
Saturday – Sunday	hr/min	**OC2**							-
Latest **De-Synchronising** time:									
Monday – Thursday	hr/min	**OC2**							-
Friday	hr/min	**OC2**							-
Saturday – Sunday	hr/min	**OC2**							-
SYNCHRONISING PARAMETERS									
Notice to Deviate from Zero (NDZ) after 48 hour **Shutdown**	Mins	**OC2**							
Station **Synchronising** Intervals (SI) after 48 hour **Shutdown**	Mins		-	-	-	-	-	-	
Synchronising Group (if applicable)	1 to 4	**OC2**							-

DATA DESCRIPTION	UNITS	DATA CAT.	**GENSET** OR STATION DATA						
			G1	G2	G3	G4	G5	G6	STN
Synchronising Generation (SYG) after 48 hour **Shutdown**	MW	**DPD & OC2**							-
De-Synchronising Intervals (Single value)	Mins	**OC2**	-	-	-	-	-	-	
RUNNING AND **SHUTDOWN** PERIOD LIMITATIONS:									
Minimum Non Zero time (MNZT) after 48 hour **Shutdown**	Mins	**OC2**							
Minimum Zero time (MZT)	Mins	**OC2**							
Two Shifting Limit (max. per day)	No.	**OC2**							
Existing AGR Plant Flexibility Limit (Existing AGR Plant only)	No.	**OC2**							
80% Reactor Thermal Power (expressed as Gross-Net MW) (**Existing AGR Plant** only)	MW	**OC2**							
Frequency Sensitive AGR Unit Limit (Frequency Sensitive AGR Units only)	No.	**OC2**							
RUN-UP PARAMETERS									
Run-up rates (RUR) after 48 hour **Shutdown**:	(Note that for DPD only a single value of run-up rate from Synch Gen to Registered Capacity is required)								
(See note 2 page 3)									
MW Level 1 (MWL1)	MW	**OC2**							-
MW Level 2 (MWL2)	MW	**OC2**							-
RUR from Synch. Gen to MWL1	MW/Mins	**DPD & OC2**							
RUR from MWL1 to MWL2	MW/Mins	**OC2**							
RUR from MWL2 to RC	MW/Mins	**OC2**							
Run-Down Rates (RDR):	(Note that for DPD only a single value of run-down rate from Registered Capacity to de-synch is required)								
MWL2	MW	**OC2**							
RDR from RC to MWL2	MW/Min	**DPD & OC2**							
MWL1	MW	**OC2**							
RDR from MWL2 to MWL1	MW/Min	**OC2**							
RDR from MWL1 to de-synch	MW/Min	**OC2**							

DATA DESCRIPTION	UNITS	DATA CAT.	GENSET OR STATION DATA						
			G1	G2	G3	G4	G5	G6	STN
REGULATION PARAMETERS									
Regulating Range	MW	**DPD**							
Load rejection capability while still **Synchronised** and able to supply **Load.**	MW	**DPD**							
GAS TURBINE LOADING PARAMETERS:									
Fast loading	MW/Min	**OC2**							
Slow loading	MW/Min	**OC2**							
CCGT MODULE PLANNING MATRIX		**OC2**	(please attach)						
POWER PARK MODULE PLANNING MATRIX		**OC2**	(please attach)						
Power Park Module Active Power Output/ Intermittent Power Source Curve (eg MW output / Wind speed)		**OC2**	(please attach)						

NOTES:

1. To allow for different groups of **Gensets** within a **Power Station** (eg. **Gensets** with the same operator) each **Genset** may be allocated to one of up to four **Synchronising Groups**. Within each such **Synchronising Group** the single synchronising interval will apply but between **Synchronising Groups** a zero synchronising interval will be assumed.

2. The run-up of a **Genset** from synchronising block load to **Registered Capacity** is represented as a three stage characteristic in which the run-up rate changes at two intermediate loads, MWL1 and MWL2. The values MWL1 & MWL2 can be different for each **Genset**.

LARGE POWER STATION OUTAGE PROGRAMMES, OUTPUT USABLE AND INFLEXIBILITY INFORMATION

(Also outline information on contracts involving **External Interconnections**)

For a **Generating Unit at a Large Power Station** the information is to be submitted on a unit basis and for a **CCGT Module** **or Power Park Module** at a **Large Power Station** the information is to be submitted on a module basis, unless otherwise stated

DATA DESCRIPTION		UNITS	TIME COVERED	UPDATE TIME	DATA CAT.
Power Station name:.......................... **Generating Unit** (or **CCGT Module** **or Power Park Module** at a **Large Power Station**) number:... **Registered Capacity**:.........................					
Large Power Station OUTAGE PROGRAMME	**Large Power Station OUTPUT USABLE**				
PLANNING FOR YEARS 3 - 7 AHEAD					

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GOVERNOR DROOP AND RESPONSE

The Data in this Schedule 4 is to be supplied by **Generators** with respect to all **Large Power Stations** and by **DC Convertor Station** owners (where agreed),, whether directly connected or **Embedded**

DATA DESCRIPTION	NORMAL VALUE	MW	DATA CAT	DROOP%			RESPONSE CAPABILITY		
				Unit 1	Unit 2	Unit 3	**Primary**	**Secondary**	**High Frequency**
MLP1	**Designed Minimum Operating Level** (for a **CCGT Module** or **Power Park Module**, on a modular basis assuming all units are **Synchronised**)								
MLP2	**Minimum Generation** (for a **CCGT Module** or **Power Park Module**, on a modular basis assuming all units are **Synchronised**)								
MLP3	70% of **Registered Capacity**								
MLP4	80% of **Registered Capacity**								
MLP5	95% of **Registered Capacity**								
MLP6	**Registered Capacity**								

Notes:

1. The data provided in this Schedule 4 is not intended to constrain any **Ancillary Services Agreement.**
2. **Registered Capacity** should be identical to that provided in Schedule 2.
3. The Governor Droop should be provided for each **Generating Unit** (excluding **Power Park Units**), **Power Park Module** or **DC Converter**. The Response Capability should be provided for each **Genset** or **DC Converter**.
4. **Primary, Secondary** and **High Frequency Response** are defined in CC.A.3.2 and are based on a frequency ramp of 0.5Hz over 10 seconds. **Primary Response** is the minimum value of response between 10s and 30s after the frequency ramp starts, **Secondary Response** between 30s and 30 minutes, and **High Frequency Response** is the minimum value after 10s on an indefinite basis.
5. For plants which have not yet **Synchronised**, the data values of MLP1 to MLP6 should be as described above. For plants which have already **Synchronised**, the values of MLP1 to MLP6 can take any value between **Designed Operating Minimum Level** and **Registered Capacity**. If MLP1 is not provided at the **Designed Minimum Operating Level**, the value of the **Designed Minimum Operating Level** should be separately stated.

USERS SYSTEM DATA

DATA DESCRIPTION	UNITS	DATA CATEGORY
PROTECTION SYSTEMS		
The following information relates only to **Protection** equipment which can trip or inter-trip or close any **Connection Point** circuit breaker or any **GB Transmission System** circuit breaker. The information need only be supplied once, in accordance with the timing requirements set out in PC.A.1.4 (b) and need not be supplied on a routine annual thereafter, although **NGC** should be notified if any of the information changes.		
(a) A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the **User's System;**		**DPD**
(b) A full description of any auto-reclose facilities installed or to be installed on the **User's System**, including type and time delays;		**DPD**
(c) A full description, including estimated settings, for all relays and **Protection** systems installed or to be installed on the **Power Park Module** or **Generating Unit's** generator transformer, unit transformer, station transformer and their associated connections;		**DPD**
(d) For **Generating Units** (other than **Power Park Units**) having a circuit breaker at the generator terminal voltage clearance times for electrical faults within the **Generating Unit** zone must be declared.		**DPD**
(e) Fault Clearance Times:		
Most probable fault clearance time for electrical faults on any part of the **Users System** directly connected to the **GB Transmission System**.	mSec	**DPD**

DATA DESCRIPTION	UNITS	DATA CATEGORY
POWER PARK MODULE/UNIT PROTECTION SYSTEMS		
Details of settings for the **Power Park Module/Unit** protection relays (to include):		
(a) Under **Frequency**,		**DPD**
(b) Over **Frequency**,		**DPD**
(c) Under Voltage, Over Voltage,		**DPD**
(d) Rotor Over current		**DPD**
(e) Stator Over current,.		**DPD**
(f) High Wind Speed Shut Down Level		**DPD**

MOTHBALLED GENERATING UNIT MOTHBALLED POWER PARK MODULE OR MOTHBALLED DC CONVERTER AT A DC CONVERTER STATION INFORMATION

The following data items must be supplied with respect to each **Mothballed Generating Unit Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter station**

Power Station________________________________ **Generating Unit , Power Park Module** or **DC Converter** Name (e.g. Unit 1)

DATA DESCRIPTION	UNITS	DATA CAT	**GENERATING UNIT** DATA						
			<1 month	1-2 months	2-3 months	3-6 months	6-12 months	>12 months	Total MW being returned
MW output that can be returned to service	MW	DPD							

Notes
1. The time periods identified in the above table represent the estimated time it would take to return the **Mothballed Generating Unit, Mothballed Power Park Module** or **Mothballed DC Converter at a DC Converter Station** to service once a decision to return has been made.
2. Where a **Mothballed Generating Unit, Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter Station** can be physically returned in stages covering more than one of the time periods identified in the above table then information should be provided for each applicable time period.
3. The estimated notice to physically return MW output to service should be determined in accordance with **Good Industry Practice** assuming normal working arrangements and normal plant procurement lead times.
4. The MW output values in each time period should be incremental MW values, e.g. if 150MW could be returned in 2 – 3 months and an additional 50MW in 3 – 6 months then the values in the columns should be Nil, Nil, 150, 50, Nil, Nil, 200 respectively.
5. Significant factors which may prevent the **Mothballed Generating Unit, Mothballed Power Park Module** or **Mothballed DC Converter** at a **DC Converter Station** -achieving the estimated values provided in this table, excluding factors relating to **Transmission Entry Capacity**, should be appended separately.

< End of **Data Registration Code** (**DRC**) >

GENERAL CONDITIONS

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GC.5 COMMUNICATION BETWEEN **NGC** AND **USERS**

GC.5.1 Unless otherwise specified in the **Grid Code**, all instructions given by **NGC** and communications (other than relating to the submission of data and notices) between **NGC** and **Users** (other than **Generators**, **DC Converter Station** owners or **Suppliers**) shall take place between the **NGC Control Engineer** based at the **Transmission Control Centre** notified by **NGC** to each **User** prior to connection, and the relevant **User Responsible Engineer/Operator**, who, in the case of a **Network Operator**, will be based at the **Control Centre** notified by the **Network Operator** to **NGC** prior to connection.

GC.5.2 Unless otherwise specified in the **Grid Code** all instructions given by **NGC** and communications (other than relating to the submission of data and notices) between **NGC** and **Generators** and/or **DC Converter Station** owners and/or **Suppliers** shall take place between the **NGC Control Engineer** based at the **Transmission Control Centre** notified by **NGC** to each **Generator** or **DC Converter Station** owner prior to connection, or to each **Supplier** prior to submission of **BM Unit Data**, and either the relevant **Generator's** or **DC Converter Station** owner's or **Supplier's Trading Point** (if it has established one) notified to **NGC** or the **Control Point** of the **Supplier** or the **Generator's Power Station** or **DC Converter Station**, as specified in each relevant section of the **Grid Code**. In the absence of notification to the contrary, the **Control Point** of a **Generator's Power Station** will be deemed to be the **Power Station** at which the **Generating Units** or **Power Park Modules** are situated.

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GC.5.5 If any **Trading Point** notified to **NGC** by a **Generator** or **DC Converter Station** owner prior to connection, or by a **Supplier** prior to submission of **BM Unit Data**, is moved to another location or is shut down, the **Generator**, **DC Converter Station** owner or **Supplier** shall immediately notify **NGC**.

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Appendix to the **General Conditions**

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GC.A1.4 The provisions of GC.2.1 shall not apply in respect of this Appendix to the **General Conditions**, and in this Appendix to the **General Conditions** the term "**Users**" means:

(a) **Generators**;

(b) **Network Operators**;

(c) **Non-Embedded Customers**;

(d) **Suppliers**;

(e) **BM Participants**; and

(f) **Externally Interconnected System Operators**

(g) **DC Converter Station** owners,

to the extent that the provisions of this Appendix to the **General Conditions** affect the rights and obligations of such **Users** under the other provisions of the **GB Grid Code**.

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< End of GC >