## CONNECTION CONDITIONS (CC)

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CC.1 INTRODUCTION

CC.1.1 The Connection Conditions ("CC") specify both:

(a) the minimum technical, design and operational criteria which must be complied with by:
   (i) any User connected to or seeking connection with the National Electricity Transmission System, or
   (ii) 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 or Offshore, and

(b) the minimum technical, design and operational criteria with which NGET will comply in relation to the part of the National Electricity Transmission System at the Connection Site with Users. In the case of any OTSDUW Plant and Apparatus, the CC also specify the minimum technical, design and operational criteria which must be complied with by the User when undertaking OTSDUW.

CC.2 OBJECTIVE

CC.2.1 The objective of the CC is to ensure that by specifying minimum technical, design and operational criteria the basic rules for connection to the National Electricity Transmission System and (for certain Users) to a User's System are similar for all Users of an equivalent category and will enable NGET to comply with its statutory and Transmission Licence obligations.

CC.2.2 In the case of any OTSDUW the objective of the CC is to ensure that by specifying the minimum technical, design and operational criteria the basic rules relating to an Offshore Transmission System designed and constructed by an Offshore Transmission Licensee and designed and/or constructed by a User under the OTSDUW Arrangements are equivalent.

CC.2.3 Provisions of the CC which apply in relation to OTSDUW and OTSUA, and/or a Transmission Interface Site, shall (in any particular case) apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply, without prejudice to the continuing application of provisions of the CC applying in relation to the relevant Offshore Transmission System and/or Connection Site. It is the case therefore that in cases where the OTSUA become operational prior to the OTSUA Transfer Time that a Generator is required to comply with this CC both as it applies to its Plant and Apparatus at a Connection Site/Connection Point and the OTSUA at the Transmission Interface Site/Transmission Interface Point until the OTSUA Transfer Time and this CC shall be construed accordingly.

CC.2.4 In relation to OTSDUW, provisions otherwise to be contained in a Bilateral Agreement may be contained in the Construction Agreement, and accordingly a reference in the CC to a relevant Bilateral Agreement includes the relevant Construction Agreement.

CC.3 SCOPE

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

(a) Generators (other than those which only have Embedded Small Power Stations), including those undertaking OTSDUW;

(b) Network Operators;

(c) Non-Embedded Customers;

(d) DC Converter Station owners; and

(e) BM Participants and Externally Interconnected System Operators in respect of CC.6.5 only.
CC.3.2 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.3.3 Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement Provisions.

The following provisions apply in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement:

CC.3.3.1 The obligations within the CC that are expressed to be applicable to Generators in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and DC Converter Station Owners in respect of Embedded DC Converter Stations not subject to a Bilateral Agreement (where the obligations are in each case listed in CC.3.3.2) shall be read and construed as obligations that the Network Operator within whose System any such Medium Power Station or DC Converter Station is Embedded must ensure are performed and discharged by the Generator or the DC Converter Station owner. Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement which are located Offshore and which are connected to an Onshore User System will be required to meet the applicable requirements of the Grid Code as though they are an Onshore Generator or Onshore DC Converter Station Owner connected to an Onshore User System Entry Point.

CC.3.3.2 The Network Operator within whose System a Medium Power Station not subject to a Bilateral Agreement is Embedded or a DC Converter Station not subject to a Bilateral Agreement is Embedded must ensure that the following obligations in the CC are performed and discharged by the Generator in respect of each such Embedded Medium Power Station or the DC Converter Station owner in the case of an Embedded DC Converter Station:

CC.5.1
CC.5.2.2
CC.5.3
CC.6.1.3
CC.6.1.5 (b)
CC.6.3.2, CC.6.3.3, CC.6.3.4, CC.6.3.6, CC.6.3.7, CC.6.3.8, CC.6.3.9, CC.6.3.10, CC.6.3.12, CC.6.3.13, CC.6.3.15, CC.6.3.16
CC.6.4.4
CC.6.5.6 (where required by CC.6.4.4)

In respect of CC.6.2.2.2, CC.6.2.2.3, CC.6.2.2.5, CC.6.1.5(a), CC.6.1.5(b) and CC.6.3.11 equivalent provisions as co-ordinated and agreed with the Network Operator and Generator or DC Converter Station owner may be required. Details of any such requirements will be notified to the Network Operator in accordance with CC.3.5.

CC.3.3.3 In the case of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement the requirements in:

CC.6.1.6
CC.6.3.8
CC.6.3.12
that would otherwise have been specified in a Bilateral Agreement will be notified to the relevant Network Operator in writing in accordance with the provisions of the CUSC and the Network Operator must ensure such requirements are performed and discharged by the Generator or the DC Converter Station owner.

CC.3.4

In the case of Offshore Embedded Power Stations connected to an Offshore User's System which directly connects to an Offshore Transmission System, any additional requirements in respect of such Offshore Embedded Power Stations may be specified in the relevant Bilateral Agreement with the Network Operator or in any Bilateral Agreement between NGET and such Offshore Embedded Power Station.

CC.3.5

In the case of a Generator undertaking OTSDUW connecting to an Onshore Network Operator's System, any additional requirements in respect of such OTSDUW Plant and Apparatus will be specified in the relevant Bilateral Agreement with the Generator. For the avoidance of doubt, requirements applicable to Generators undertaking OTSDUW and connecting to a Network Operator's User System, shall be consistent with those applicable requirements of Generators undertaking OTSDUW and connecting to a Transmission Interface Point.

CC.4

PROCEDURE

CC.4.1

The CUSC contains certain provisions relating to the procedure for connection to the National Electricity 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 and during the course of NGET notifying the User that it has the right to become operational. The procedure for a User to become connected is set out in the Compliance Processes.

CC.5

CONNECTION

CC.5.1

The provisions relating to connecting to the National Electricity 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:

(a) the CUSC and/or CUSC Contract (or in the relevant application form or offer for a CUSC Contract);

(b) or, in the case of an Embedded Development, the relevant Distribution Code and/or the Embedded Development Agreement for the connection (or in the relevant application form or offer for an Embedded Development Agreement),

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 (and their equivalents in the case of Embedded Medium Power Stations not subject to a Bilateral Agreement or Embedded DC Converter Stations not subject to a Bilateral Agreement). References in the CC to the “Bilateral Agreement” and/or “Construction Agreement” and/or “Embedded Development Agreement” shall be deemed to include references to the application form or offer therefor.

CC.5.2

Items For Submission

CC.5.2.1

Prior to the Completion Date (or, where the Generator is undertaking OTSDUW, any later date specified) under the Bilateral Agreement and/or Construction Agreement, the following is submitted pursuant to the terms of the Bilateral Agreement and/or Construction Agreement:
(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) copies of all Safety Rules and Local Safety Instructions applicable at Users’ Sites which will be used at the NGET/User interface (which, for the purpose of OC8, must be to NGET’s satisfaction regarding the procedures for Isolation and Earthing. For User Sites in Scotland and Offshore NGET will consult the Relevant Transmission Licensee when determining whether the procedures for Isolation and Earthing are satisfactory);

(d) information to enable NGET to prepare Site Responsibility Schedules on the basis of the provisions set out in Appendix 1;

(e) an Operation Diagram for all HV Apparatus on the User side of the Connection Point as described in CC.7;

(f) the proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

(g) written confirmation that Safety Co-ordinators acting on behalf of the User are authorised and competent pursuant to the requirements of OC8;

(h) RISSP prefixes pursuant to the requirements of OC8. NGET is required to circulate prefixes utilising a proforma in accordance with OC8;

(i) a list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorised to make binding decisions on behalf of the User, pursuant to OC9;

(j) a list of managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User;

(k) information to enable NGET to prepare Site Common Drawings as described in CC.7;

(l) a list of the telephone numbers for the Users facsimile machines referred to in CC.6.5.9; and

(m) for Sites in Scotland and Offshore a list of persons appointed by the User to undertake operational duties on the User’s System (including any OTSDUW prior to the OTSUA Transfer Time) and to issue and receive operational messages and instructions in relation to the User’s System (including any OTSDUW prior to the OTSUA Transfer Time); and an appointed person or persons responsible for the maintenance and testing of User’s Plant and Apparatus.

Prior to the Completion Date the following must be submitted to NGET by the Network Operator in respect of an Embedded Development:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) the proposed name of the Embedded Medium Power Station or Embedded DC Converter Station Site (which shall be agreed with NGET unless it is the same as, or confusingly similar to, the name of other Transmission Site or User Site);
CC.5.2.3 Prior to the Completion Date contained within an Offshore Transmission Distribution Connection Agreement the following must be submitted to NGET by the Network Operator in respect of a proposed new Interface Point within its User System:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

CC.5.2.4 In the case of OTSDUW Plant and Apparatus (in addition to items under CC.5.2.1 in respect of the Connection Site), prior to the Completion Date (or any later date specified) under the Construction Agreement the following must be submitted to NGET by the User in respect of the proposed new Connection Point and Interface Point:

(a) updated Planning Code data (Standard Planning Data, Detailed Planning Data and OTSDUW Data and Information), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) information to enable preparation of the Site Responsibility Schedules at the Transmission Interface Site on the basis of the provisions set out in Appendix 1.

(d) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

CC.5.3 (a) Of the items CC.5.2.1 (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.5.2.1(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.5.2.1(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.

CC.5.4 In addition, at the time the information is given under CC.5.2(g), NGET will provide written confirmation to the User that the Safety Co-ordinators acting on behalf of NGET are authorised and competent pursuant to the requirements of OC8.

CC.6 TECHNICAL, DESIGN AND OPERATIONAL CRITERIA

CC.6.1 National Electricity Transmission System Performance Characteristics

CC.6.1.1 NGET shall ensure that, subject as provided in the Grid Code, the National Electricity Transmission System complies with the following technical, design and operational criteria in relation to the part of the National Electricity Transmission System at the Connection Site with a User and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point (unless otherwise specified in CC.6) although in relation to operational criteria NGET may be unable (and will not be required) to comply with this obligation to the extent that there are insufficient Power Stations or User Systems are not available or Users do not comply with NGET’s instructions or otherwise do not comply with the Grid Code and each User shall ensure that its Plant and Apparatus complies with the criteria set out in CC.6.1.5.
Grid Frequency Variations

CC.6.1.2 The Frequency of the National Electricity Transmission System shall be nominally 50Hz and shall be controlled within the limits of 49.5 - 50.5Hz unless exceptional circumstances prevail.

CC.6.1.3 The System Frequency could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of User's Plant and Apparatus and OTSDUW Plant and Apparatus must enable operation of that Plant and Apparatus within that range in accordance with the following:

<table>
<thead>
<tr>
<th>Frequency Range</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>51.5Hz - 52Hz</td>
<td>Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz.</td>
</tr>
<tr>
<td>51Hz - 51.5Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz.</td>
</tr>
<tr>
<td>49.0Hz - 51Hz</td>
<td>Continuous operation is required</td>
</tr>
<tr>
<td>47.5Hz - 49.0Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz.</td>
</tr>
<tr>
<td>47Hz - 47.5Hz</td>
<td>Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz.</td>
</tr>
</tbody>
</table>

For the avoidance of doubt, disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz, unless agreed with NGET in accordance with CC.6.3.12.

Grid Voltage Variations

CC.6.1.4 Subject as provided below, the voltage on the 400kV part of the National Electricity Transmission System at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point) will normally remain within ±5% of the nominal value unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail. Voltages on the 275kV and 132kV parts of the National Electricity Transmission System at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point) will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail. At nominal System voltages below 132kV the voltage of the National Electricity Transmission System at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point) will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, voltage may collapse transiently to zero at the point of fault until the fault is cleared. The normal operating ranges of the National Electricity Transmission System are summarised below:

<table>
<thead>
<tr>
<th>National Electricity Transmission System</th>
<th>Normal Operating Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal Voltage</td>
<td></td>
</tr>
<tr>
<td>400kV</td>
<td>400kV ±5%</td>
</tr>
<tr>
<td>275kV</td>
<td>275kV ±10%</td>
</tr>
<tr>
<td>132kV</td>
<td>132kV ±10%</td>
</tr>
</tbody>
</table>

NGET and a User may agree greater or lesser variations in voltage to those set out above in relation to a particular Connection Site, and insofar as a greater or lesser variation is agreed, the relevant figure set out above shall, in relation to that User at the particular Connection Site, be replaced by the figure agreed.
Voltage Waveform Quality

CC.6.1.5 All Plant and Apparatus connected to the National Electricity Transmission System, and that part of the National Electricity Transmission System at each Connection Site or, in the case of OTSDUW Plant and Apparatus, at each Interface Point, 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 Onshore 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. The Electromagnetic Compatibility Levels for harmonic distortion on an Offshore Transmission System will be defined in relevant Bilateral Agreements.

Engineering Recommendation G5/4 contains planning criteria which NGET will apply to the connection of non-linear Load to the National Electricity Transmission System, which may result in harmonic emission limits being specified for these 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 (and OTSDUW 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.

(b) Phase Unbalance

Under Planned Outage conditions, the weekly 95 percentile of Phase (Voltage) Unbalance, calculated in accordance with IEC 61000-4-30 and IEC 61000-3-13, on the National Electricity Transmission System for voltages above 150kV should remain, in England and Wales, below 1.5%, and in Scotland, below 2%, and for voltages of 150kV and below, across GB below 2%, unless abnormal conditions prevail and Offshore (or in the case of OTSDUW, OTSDUW Plant and Apparatus) will be defined in relevant Bilateral Agreements.

The Phase Unbalance is calculated from the ratio of root mean square (rms) of negative phase sequence voltage to rms of positive phase sequence voltage, based on 10-minute average values, in accordance with IEC 61000-4-30.

CC.6.1.6 Across GB, under the Planned Outage conditions stated in CC.6.1.5(b) infrequent short duration peaks with a maximum value of 2% are permitted for Phase (Voltage) Unbalance, for voltages above 150kV, subject to the prior agreement of NGET under the Bilateral Agreement and in relation to OTSDUW, the Construction Agreement. NGET will only agree following a specific assessment of the impact of these levels on Transmission Apparatus and other Users Apparatus with which it is satisfied.

Voltage Fluctuations

CC.6.1.7 Voltage changes at a Point of Common Coupling on the Onshore Transmission System shall not exceed:

(a) The limits specified in Table CC.6.1.7 with the stated frequency of occurrence, where:

\[
\%\Delta V_{\text{steadystate}} = \left| 100 \times \frac{\Delta V_{\text{steadystate}}}{V_0} \right|
\]

and

\[
\%\Delta V_{\max} = 100 \times \frac{\Delta V_{\max}}{V_0} ;
\]
(ii) $V_0$ is the initial steady state system voltage;

(iii) $V_{\text{steady state}}$ is the system voltage reached when the rate of change of system voltage over time is less than or equal to 0.5% over 1 second and $\Delta V_{\text{steady state}}$ is the absolute value of the difference between $V_{\text{steady state}}$ and $V_0$;

(iv) $\Delta V_{\text{max}}$ is the absolute value of the maximum change in the system voltage relative to the initial steady state system voltage of $V_0$;

(v) All voltages are the root mean square of the voltage measured over one cycle refreshed every half a cycle as per IEC 61000-4-30;

(vi) The voltage changes specified are the absolute maximum allowed, applied to phase to ground or phase to phase voltages whichever is the highest change;

(vii) Voltage changes in category 3 do not exceed the limits depicted in the time dependant characteristic shown in Figure CC.6.1.7;

(viii) Voltage changes in category 3 only occur infrequently, typically not planned more than once per year on average over the lifetime of a connection, and in circumstances notified to NGET, such as for example commissioning in accordance with a commissioning programme, implementation of a planned outage notified in accordance with OC2 or an Operation or Event notified in accordance with OC7; and

(ix) For connections with a Completion Date after 1st September 2015 and where voltage changes would constitute a risk to the National Electricity Transmission System or, in NGET’s view, the System of any User, Bilateral Agreements may include provision for NGET to reasonably limit the number of voltage changes in category 2 or 3 to a lower number than specified in Table CC.6.1.7 to ensure that the total number of voltage changes at the Point of Common Coupling across multiple Users remains within the limits of Table CC.6.1.7.

<table>
<thead>
<tr>
<th>Category</th>
<th>Maximum number of Occurrences</th>
<th>$%\Delta V_{\text{max}}$ &amp; $%\Delta V_{\text{steady state}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>No Limit</td>
<td>$\left</td>
</tr>
<tr>
<td>2</td>
<td>$\frac{3600}{0.304 \sqrt{2.5 \times %\Delta V_{\text{max}}}}$ occurrences per hour with events evenly distributed</td>
<td>$1% &lt; \left</td>
</tr>
<tr>
<td>3</td>
<td>No more than 4 per day for Commissioning, Maintenance and Fault Restoration</td>
<td>For decreases in voltage: $%\Delta V_{\text{max}} \leq 12%$ &amp; $%\Delta V_{\text{steady state}} \leq 3%$ For increases in voltage: $%\Delta V_{\text{max}} \leq 5%$ &amp; $%\Delta V_{\text{steady state}} \leq 3%$ (see Figure CC6.1.7)</td>
</tr>
</tbody>
</table>

Table CC.6.1.7 - Limits for Rapid Voltage Changes
A decrease in voltage of up to 12% is permissible for up to 80ms, as highlighted in the shaded area in Figure CC.6.1.7, reducing to up to 10% after 80ms and to up to 3% after 2 seconds.

An increase in voltage of up to 5% is permissible if it is reduced to up to 3% after 0.5 seconds.

Voltage fluctuations at a Point of CommonCoupling with a fluctuating Load directly connected to an Offshore Transmission System (or in the case of OTSDUW, OTSDUW Plant and Apparatus) shall not exceed the limits set out in the Bilateral Agreement.

Sub-Synchronous Resonance and Sub-Synchronous Torsional Interaction

NGET shall ensure where necessary, and in consultation with Transmission Licensees where required, that any relevant site specific conditions applicable at a User’s Connection Site, including a description of the Sub-Synchronous Oscillation conditions considered in the application of the relevant License Standards, are set out in the User’s Bilateral Agreement.
CC.6.2 Plant and Apparatus relating to Connection Site and Interface Point

The following requirements apply to Plant and Apparatus relating to the Connection Point, and OTSDUW Plant and Apparatus relating to the Interface Point (until the OTSUA Transfer Time) and Connection Point which (except as otherwise provided in the relevant paragraph) each User must ensure are complied with in relation to its Plant and Apparatus and which in the case of CC.6.2.2.2, CC.6.2.3.1.1 and CC.6.2.1.1(b) only, NGET must ensure are complied with in relation to Transmission Plant and Apparatus, as provided in those paragraphs.

CC.6.2.1 General Requirements

CC.6.2.1.1 (a) The design of connections between the National Electricity 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. In the case of OTSDUW, the design of the OTSUA’s connections at the Interface Point and Connection Point will be consistent with Licence Standards.

(b) The National Electricity Transmission System (and any OTSDUW Plant and Apparatus) at nominal System voltages of 132kV and above is/shall be designed to be earthed with an Earth Fault Factor of, in England and Wales or Offshore, below 1.4 and in Scotland, below 1.5. Under fault conditions the rated Frequency component of voltage could fall transiently to zero on one or more phases or, in England and Wales, rise to 140% phase-to-earth voltage, or in Scotland, rise to 150% phase-to-earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase-to-earth.

(c) For connections to the National Electricity Transmission System at nominal System voltages of below 132kV the earthing requirements and voltage rise conditions will be advised by NGET as soon as practicable prior to connection and in the case of OTSDUW Plant and Apparatus shall be advised to NGET by the User.

CC.6.2.1.2 Substation Plant and Apparatus

(a) The following provisions shall apply to all Plant and Apparatus which is connected at the voltage of the Connection Point (and OTSDUW Plant and Apparatus at the Interface Point) and which is contained in equipment bays that are within the Transmission busbar Protection zone at the Connection Point. This includes circuit breakers, switch disconnectors, disconnectors, Earthing Devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination devices. Where necessary, this is as more precisely defined in the Bilateral Agreement.

(i) Plant and/or Apparatus prior to 1st January 1999

Each item of such Plant and/or Apparatus which at 1st January 1999 is either:

installed; or

owned (but is either in storage, maintenance or awaiting installation); or

ordered;

and is the subject of a Bilateral Agreement with regard to the purpose for which it is in use or intended to be in use, shall comply with the relevant
standards/specifications applicable at the time that the **Plant** and/or **Apparatus** was designed (rather than commissioned) and any further requirements as specified in the **Bilateral Agreement**.

(ii) **Plant and/or Apparatus post 1st January 1999 for a new Connection Point** (including OTSDUW Plant and Apparatus at the Interface Point)

Each item of such **Plant** and/or **Apparatus** installed in relation to a new **Connection Point** (or OTSDUW Plant and Apparatus at the Interface Point) after 1st January 1999 shall comply with the relevant **Technical Specifications** and any further requirements identified by **NGET**, acting reasonably, to reflect the options to be followed within the **Technical Specifications** and/or to complement if necessary the **Technical Specifications** so as to enable **NGET** to comply with its obligations in relation to the **National Electricity Transmission System** or, in Scotland or **Offshore**, the **Relevant Transmission Licensee** to comply with its obligations in relation to its **Transmission System**. This information, including the application dates of the relevant **Technical Specifications**, will be as specified in the **Bilateral Agreement**.

(iii) **New Plant and/or Apparatus post 1st January 1999 for an existing Connection Point** (including OTSDUW Plant and Apparatus at the Interface Point)

Each new additional and/or replacement item of such **Plant** and/or **Apparatus** installed in relation to a change to an existing **Connection Point** (or OTSDUW Plant and Apparatus at the Interface Point and **Connection Point**) after 1st January 1999 shall comply with the standards/specifications applicable when the change was designed, or such other standards/specifications as necessary to ensure that the item of **Plant** and/or **Apparatus** is reasonably fit for its intended purpose having due regard to the obligations of **NGET**, the relevant **User** and, in Scotland, or **Offshore**, also the **Relevant Transmission Licensee** under their respective **Licences**. Where appropriate this information, including the application dates of the relevant standards/specifications, will be as specified in the varied **Bilateral Agreement**.

(iv) **Used Plant and/or Apparatus being moved, re-used or modified**

If, after its installation, any such item of **Plant** and/or **Apparatus** is subsequently:

- moved to a new location; or
- used for a different purpose; or
- otherwise modified;

then the standards/specifications as described in (i), (ii), or (iii) above as applicable will apply as appropriate to such **Plant** and/or **Apparatus**, which must be reasonably fit for its intended purpose having due regard to the obligations of **NGET**, the relevant **User** and, in Scotland or **Offshore**, also the **Relevant Transmission Licensee** under their respective **Licences**.

(b) **NGET** shall at all times maintain a list of those **Technical Specifications** and additional requirements which might be applicable under this CC.6.2.1.2 and which may be referenced by **NGET** in the **Bilateral Agreement**. **NGET** shall provide a copy of the list upon request to any **User**. **NGET** shall also provide a copy of the list to any new **User** upon receipt of an application form for a **Bilateral Agreement** for a new **Connection Point**.

(c) Where the **User** provides **NGET** with information and/or test reports in respect of **Plant** and/or **Apparatus** which the **User** reasonably believes demonstrate the compliance of such items with the provisions of a **Technical Specification** then **NGET** shall promptly and without unreasonable delay give due and proper consideration to such information.
(d) **Plant and Apparatus** shall be designed, manufactured and tested in premises with an accredited certificate in accordance with the quality assurance requirements of the relevant standard in the BS EN ISO 9000 series (or equivalent as reasonably approved by NGET) or in respect of test premises which do not include a manufacturing facility premises with an accredited certificate in accordance with BS EN 45001.

(e) Each connection between a **User** and the **National Electricity Transmission System** must be controlled by a circuit-breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the point of connection. The **Seven Year Statement** gives values of short circuit current and the rating of **Transmission** circuit breakers at existing and committed **Connection Points** for future years.

(f) Each connection between a **Generator** undertaking OTSDUW or an **Onshore Transmission Licensee**, must be controlled by a circuit breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the **Transmission Interface Point**. The **Seven Year Statement** gives values of short circuit current and the rating of **Transmission** circuit breakers at existing and committed **Transmission Interface Points** for future years.

**CC.6.2.2 Requirements at Connection Points or, in the case of OTSDUW at Interface Points that relate to Generators or OTSDUW Plant and Apparatus or DC Converter Station owners**

**CC.6.2.2.1 Not Used.**

**CC.6.2.2.2 Generating Unit, OTSDUW Plant and Apparatus and Power Station Protection Arrangements**

**CC.6.2.2.2.1 Minimum Requirements**

**Protection** of Generating Units (other than Power Park Units), DC Converters, **OTSDUW Plant and Apparatus** or Power Park Modules and their connections to the **National Electricity Transmission System** shall meet the requirements given below. These are necessary to reduce the impact on the **National Electricity Transmission System** of faults on **OTSDUW Plant and Apparatus** circuits or circuits owned by Generators or DC Converter Station owners.

**CC.6.2.2.2.2 Fault Clearance Times**

(a) The required fault clearance time for faults on the Generator's or DC Converter Station owner's equipment directly connected to the **National Electricity Transmission System** or **OTSDUW Plant and Apparatus** and for faults on the **National Electricity Transmission System** directly connected to the Generator or DC Converter Station owner's equipment or **OTSDUW Plant and Apparatus**, from fault inception to the circuit breaker arc extinction, shall be set out in the **Bilateral Agreement**. The fault clearance time specified in the **Bilateral Agreement** shall not be shorter than the durations specified below:

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

but this shall not prevent the **User** or **NGET** or the **Generator** (including in respect of OTSDUW Plant and Apparatus) from selecting a shorter fault clearance time on their own **Plant and Apparatus** provided **Discrimination** is achieved.

A longer fault clearance time may be specified in the **Bilateral Agreement** for faults on the **National Electricity Transmission System**. A longer fault clearance time for faults on the **Generator** or **DC Converter Station** owner's equipment or **OTSDUW Plant and Apparatus** may be agreed with NGET in accordance with the terms of the **Bilateral Agreement** but only if **System** requirements, in NGET’s view, permit. The probability that the fault clearance time stated in the **Bilateral Agreement** will be exceeded by any given fault, must be less than 2%.
(b) In the event that the required fault clearance time is not met as a result of failure to operate on the Main Protection System(s) provided, the Generators or DC Converter Station owners or Generators in the case of OTSDUW Plant and Apparatus shall, except as specified below provide Independent Back-Up Protection. NGET will also provide Back-Up Protection and NGET and the User’s Back-Up Protections will be co-ordinated so as to provide Discrimination.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus in respect of which the Completion Date is after 20 January 2016 and connected to the National Electricity Transmission System at 400kV or 275kV and where two Independent Main Protections are provided to clear faults on the HV Connections within the required fault clearance time, the Back-Up Protection provided by the Generators (including in respect of OTSDUW Plant and Apparatus) and DC Converter Station owner shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections. Where two Independent Main Protections are installed the Back-Up Protection may be integrated into one (or both) of the Independent Main Protection relays.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus in respect of which the Completion Date is after 20 January 2016 and connected to the National Electricity Transmission System at 132 kV and where only one Main Protection is provided to clear faults on the HV Connections within the required fault clearance time, the Independent Back-Up Protection provided by the Generator (including in respect of OTSDUW Plant and Apparatus) and the DC Converter Station owner shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus connected to the National Electricity Transmission System and on Generating Units (other than a Power Park Unit), DC Converters or Power Park Modules or OTSDUW Plant and Apparatus connected to the National Electricity Transmission System at 400 kV or 275 kV or 132 kV, in respect of which the Completion Date is before the 20 January 2016, the Back-Up Protection or Independent Back-Up Protection shall operate to give a fault clearance time of no longer than 800ms in England and Wales or 300ms in Scotland at the minimum infeed for normal operation for faults on the HV Connections.

A Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus with Back-Up Protection or Independent Back-Up Protection will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the National Electricity Transmission System by breaker fail Protection at 400kV or 275kV or of a fault cleared by Back-Up Protection where the Generator (including in the case of OTSDUW Plant and Apparatus) or DC Converter is connected at 132kV and below. This will permit Discrimination between Generator in respect of OTSDUW Plant and Apparatus or DC Converter Station owners’ Back-Up Protection or Independent Back-Up Protection and the Back-Up Protection provided on the National Electricity Transmission System and other Users’ Systems.
(c) When the Generating Unit (other than Power Park Units), or the DC Converter or Power Park Module or OTSDUW Plant and Apparatus is connected to the National Electricity Transmission System at 400kV or 275kV, and in Scotland and Offshore also at 132kV, and a circuit breaker is provided by the Generator (including in respect of OTSDUW Plant and Apparatus) or the DC Converter Station owner, or NGET, as the case may be, to interrupt fault current interchange with the National Electricity 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 (including in respect of OTSDUW Plant and Apparatus) or DC Converter Station owner, or NGET, 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 200ms.

(d) The target performance for the System Fault Dependability Index shall be not less than 99%. This is a measure of the ability of Protection to initiate successful tripping of circuit breakers which are associated with the faulty item of Apparatus.

CC.6.2.2.3 Equipment to be provided

CC.6.2.2.3.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement. In this CC the term “interconnecting connections” means the primary conductors from the current transformer accommodation on the circuit side of the circuit breaker to the Connection Point or the primary conductors from the current transformer accommodation on the circuit side of the OTSDUW Plant and Apparatus of the circuit breaker to the Transmission Interface Point.

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.6.2.2.3.3 Loss of Excitation

The Generator must provide Protection to detect loss of excitation on a Generating Unit and initiate a Generating Unit trip.

CC.6.2.2.3.4 Pole-Slipping Protection

Where, in NGET’s reasonable opinion, System requirements dictate, NGET will specify in the Bilateral Agreement a requirement for Generators to fit pole-slipping Protection on their Generating Units.

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 NGET or in Scotland or Offshore, a representative of NGET, or written authority from NGET to perform such work or alterations in the absence of a representative of NGET.
CC.6.2.2.5 Relay Settings
Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement and in relation to OTSDUW Plant and Apparatus, across the Interface Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

CC.6.2.3 Requirements at Connection Points relating to Network Operators and Non-Embedded Customers

CC.6.2.3.1 Protection Arrangements for Network Operators and Non-Embedded Customers

CC.6.2.3.1.1 Protection of Network Operator and Non-Embedded Customers User Systems directly connected to the National Electricity Transmission System, shall meet the requirements given below:

Fault Clearance Times

(a) The required fault clearance time for faults on Network Operator and Non-Embedded Customer equipment directly connected to the National Electricity Transmission System, and for faults on the National Electricity Transmission System directly connected to the Network Operator’s or Non-Embedded Customer’s equipment, from fault inception to the circuit breaker arc extinction, shall be set out in each Bilateral Agreement. The fault clearance time specified in the Bilateral Agreement shall not be shorter than the durations specified below:

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

but this shall not prevent the User or NGET from selecting a shorter fault clearance time on its own Plant and Apparatus provided Discrimination is achieved.

For the purpose of establishing the Protection requirements in accordance with CC.6.2.3.1.1 only, the point of connection of the Network Operator or Non-Embedded Customer equipment to the National Electricity Transmission System shall be deemed to be the low voltage busbars at a Grid Supply Point, irrespective of the ownership of the equipment at the Grid Supply Point.

A longer fault clearance time may be specified in the Bilateral Agreement for faults on the National Electricity Transmission System. A longer fault clearance time for faults on the Network Operator and Non-Embedded Customers equipment may be agreed with NGET in accordance with the terms of the Bilateral Agreement but only if System requirements in NGET’s view permit. The probability that the fault clearance time stated in the Bilateral Agreement will be exceeded by any given fault must be less than 2%.

(b) (i) For the event of failure of the Protection systems provided to meet the above fault clearance time requirements, Back-Up Protection shall be provided by the Network Operator or Non-Embedded Customer as the case may be.

(ii) NGET will also provide Back-Up Protection, which will result in a fault clearance time longer than that specified for the Network Operator or Non-Embedded Customer Back-Up Protection so as to provide Discrimination.

(iii) For connections with the National Electricity Transmission System at 132kV and below, it is normally required that the Back-Up Protection on the National Electricity Transmission System shall discriminate with the Network Operator or Non-Embedded Customer’s Back-Up Protection.

(iv) For connections with the National Electricity Transmission System at 400kV or 275kV, the Back-Up Protection will be provided by the Network Operator or Non-Embedded Customer, as the case may be, with a fault clearance time not longer than 300ms for faults on the Network Operator’s or Non-Embedded Customer’s Apparatus.
(v) Such Protection will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the National Electricity Transmission System by breaker fail Protection at 400kV or 275kV. This will permit Discrimination between Network Operator’s Back-Up Protection or Non-Embedded Customer’s Back-Up Protection, as the case may be, and Back-Up Protection provided on the National Electricity Transmission System and other User Systems. The requirement for and level of Discrimination required will be specified in the Bilateral Agreement.

(c) (i) Where the Network Operator or Non-Embedded Customer is connected to the National Electricity Transmission System at 400kV or 275kV, and in Scotland also at 132kV, and a circuit breaker is provided by the Network Operator or Non-Embedded Customer, or NGET, as the case may be, to interrupt the interchange of fault current with the National Electricity Transmission System or the System of the Network Operator or Non-Embedded Customer, as the case may be, circuit breaker fail Protection will be provided by the Network Operator or Non-Embedded Customer, or NGET, as the case may be, on this circuit breaker.

(ii) 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 200ms.

(d) The target performance for the System Fault Dependability Index shall be not less than 99%. This is a measure of the ability of Protection to initiate successful tripping of circuit breakers which are associated with the faulty items of Apparatus.
CC.6.2.3.2 Fault Disconnection Facilities

(a) Where no Transmission circuit breaker is provided at the User's connection voltage, the User must provide NGET with the means of tripping all the User's circuit breakers necessary to isolate faults or System abnormalities on the National Electricity Transmission System. In these circumstances, for faults on the User's System, the User's Protection should also trip higher voltage Transmission circuit breakers. These tripping facilities shall be in accordance with the requirements specified in the Bilateral Agreement.

(b) NGET may require the installation of a System to Generator Operational Intertripping Scheme in order to enable the timely restoration of circuits following power System fault(s). These requirements shall be set out in the relevant Bilateral Agreement.

CC.6.2.3.3 Automatic Switching Equipment

Where automatic reclosure of Transmission circuit breakers is required following faults on the User's System, automatic switching equipment shall be provided in accordance with the requirements specified in the Bilateral Agreement.

CC.6.2.3.4 Relay Settings

Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

CC.6.2.3.5 Work on Protection equipment

Where a Transmission Licensee owns the busbar at the Connection Point, no busbar Protection, mesh corner Protection relays, AC or DC wiring (other than power supplies or DC tripping associated with the Network Operator or Non-Embedded Customer's Apparatus itself) may be worked upon or altered by the Network Operator or Non-Embedded Customer personnel in the absence of a representative of NGET or in Scotland, a representative of NGET, or written authority from NGET to perform such work or alterations in the absence of a representative of NGET.

CC.6.2.3.6 Equipment to be provided

CC.6.2.3.6.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement.

CC.6.3 GENERAL GENERATING UNIT (AND OTSDUW) 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 National Electricity Transmission System or Embedded) and (where provided in this section) OTSDUW Plant and Apparatus 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 and OTSDUW Plant and Apparatus 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. The performance requirements that OTSDUW Plant and Apparatus must be capable of providing at the Interface Point under this section may be provided using a combination of Generator Plant and Apparatus and/or OTSDUW Plant and Apparatus.

Plant Performance Requirements
CC.6.3.2  (a) When supplying Rated MW all Onshore Synchronous Generating Units must be capable of continuous operation at any point between the limits 0.85 Power Factor lagging and 0.95 Power Factor leading at the Onshore Synchronous Generating Unit terminals. At Active Power output levels other than Rated MW, all Onshore Synchronous Generating Units must be capable of continuous operation at any point between the Reactive Power capability limits identified on the Generator Performance Chart.

In addition to the above paragraph, where Onshore Synchronous Generating Unit(s):

(i) have a Connection Entry Capacity which has been increased above Rated MW (or the Connection Entry Capacity of the CCGT module has increased above the sum of the Rated MW of the Generating Units compromising the CCGT module), and such increase takes effect after 1st May 2009, the minimum lagging Reactive Power capability at the terminals of the Onshore Synchronous Generating Unit(s) must be 0.9 Power Factor at all Active Power output levels in excess of Rated MW. Further, the User shall comply with the provisions of and any instructions given pursuant to BC1.8 and the relevant Bilateral Agreement; or

(ii) have a Connection Entry Capacity in excess of Rated MW (or the Connection Entry Capacity of the CCGT module exceeds the sum of Rated MW of the Generating Units comprising the CCGT module) and a Completion Date before 1st May 2009, alternative provisions relating to Reactive Power capability may be specified in the Bilateral Agreement and where this is the case such provisions must be complied with.

The short circuit ratio of Onshore Synchronous Generating Units with an Apparent Power rating of less than 1600MVA shall be not less than 0.5. The short circuit ratio of Onshore Synchronous Generating Units with a rated Apparent Power of 1600MVA or above shall be not less than 0.4.

(b) Subject to paragraph (c) below, all Onshore Non-Synchronous Generating Units, Onshore DC Converters and Onshore Power Park Modules must be capable of maintaining zero transfer of Reactive Power at the Onshore Grid Entry Point (or User System Entry Point if Embedded) at all Active Power output levels under steady state voltage conditions. For Onshore Non-Synchronous Generating Units and Onshore Power Park Modules the steady state tolerance on Reactive Power transfer to and from the National Electricity Transmission System expressed in MVAr shall be no greater than 5% of the Rated MW. For Onshore DC Converters the steady state tolerance on Reactive Power transfer to and from the National Electricity Transmission System shall be specified in the Bilateral Agreement.
(c) Subject to the provisions of CC.6.3.2(d) below, all Onshore Non-Synchronous Generating Units, Onshore DC Converters (excluding current source technology) and Onshore Power Park Modules (excluding those connected to the Total System by a current source Onshore DC Converter) and OTSDUW Plant and Apparatus at the Interface Point with a Completion Date on or after 1 January 2006 must be capable of supplying Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus at any point between the limits 0.95 Power Factor lagging and 0.95 Power Factor leading at the Onshore Grid Entry Point in England and Wales or Interface Point in the case of OTSDUW Plant and Apparatus or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for Generators directly connected to the Onshore Transmission System in Scotland (or User System Entry Point if Embedded). With all Plant in service, the Reactive Power limits defined at Rated MW or Interface Point Capacity in the case of OTSDUW Plant and Apparatus at Lagging Power Factor will apply at all Active Power output levels above 20% of the Rated MW or Interface Point Capacity in the case of OTSDUW Plant and Apparatus 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 or Interface Point Capacity in the case of OTSDUW Plant and Apparatus 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 or Interface Point Capacity in the case of OTSDUW Plant and Apparatus 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.

![Figure 1](image-url)

- **Point A** is equivalent (in MVAr) to 0.95 leading Power Factor at Rated MW output or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**
- **Point B** is equivalent (in MVAr) to 0.95 lagging Power Factor at Rated MW output or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**
- **Point C** is equivalent (in MVAr) to -5% of Rated MW output or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**
Point D is equivalent (in MVar) to: +5% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus

Point E is equivalent (in MVar) to: -12% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus

(d) All Onshore Non-Synchronous Generating Units and Onshore 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 Onshore 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 Onshore 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).

(e) The short circuit ratio of Offshore Synchronous Generating Units at a Large Power Station shall be not less than 0.5. At a Large Power Station all Offshore Synchronous Generating Units, Offshore Non-Synchronous Generating Units, Offshore DC Converters and Offshore Power Park Modules must be capable of maintaining:

(i) zero transfer of Reactive Power at the Offshore Grid Entry Point for all Generators with an Offshore Grid Entry Point at the LV Side of the Offshore Platform at all Active Power output levels under steady state voltage conditions. The steady state tolerance on Reactive Power transfer to and from an Offshore Transmission System expressed in MVar shall be no greater than 5% of the Rated MW, or

(ii) a transfer of Reactive Power at the Offshore Grid Entry Point at a value specified in the Bilateral Agreement that will be equivalent to zero at the LV Side of the Offshore Platform. In addition, the steady state tolerance on Reactive Power transfer to and from an Offshore Transmission System expressed in MVar at the LV Side of the Offshore Platform shall be no greater than 5% of the Rated MW, or

(iii) the Reactive Power capability (within associated steady state tolerance) specified in the Bilateral Agreement if any alternative has been agreed with the Generator, Offshore Transmission Licensee and NGET.

(f) In addition, a Genset shall meet the operational requirements as specified in BC2.A.2.6.

CC.6.3.3 Each Generating Unit, DC Converter (including an OTSDUW 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) (subject to the provisions of CC.6.1.3) maintaining its Active Power output at a level not lower than the figure determined by the linear relationship shown in Figure 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%. In the case of a CCGT Module, the above requirement shall be retained down to the Low Frequency Relay trip setting of 48.8 Hz, which reflects the first stage of the Automatic Low Frequency Demand Disconnection scheme notified to Network Operators under OC6.6.2. For System Frequency below that setting, the existing requirement shall be retained for a minimum period of 5 minutes while System Frequency remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if System Frequency remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the Gas Turbine tripping. The need for special measure(s) is linked to the inherent Gas Turbine Active Power output reduction caused by reduced shaft speed due to falling System Frequency.

![Figure 2](image)

Note: Frequency $F_{LFDD-1}$ is the relay trip setting of the first stage of the Automatic Low Frequency Demand Disconnection Scheme.

(c) For the avoidance of doubt in the case of a Generating Unit or Power Park Module (or OTSDUW DC Converters at the Interface Point) 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 National Electricity 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%.
(e) At a Large Power Station, in the case of an Offshore Generating Unit, Offshore Power Park Module, Offshore DC Converter and OTSDUW DC Converter, the Generator shall comply with the requirements of CC.6.3.3. Generators should be aware that Section K of the STC places requirements on Offshore Transmission Licensees which utilise a Transmission DC Converter as part of their Offshore Transmission System to make appropriate provisions to enable Generators to fulfil their obligations.

(f) In the case of an OTSDUW DC Converter the OTSDUW Plant and Apparatus shall provide a continuous signal indicating the real time frequency measured at the Interface Point to the Offshore Grid Entry Point.

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 National Electricity Transmission System or in the case of OTSDUW, the Active Power transfer at the Interface Point, under steady state conditions of any OTSDUW Plant and Apparatus 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. In addition:

(a) For any Onshore Generating Unit, Onshore DC Converter and Onshore Power Park Module or OTSDUW 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 an Onshore Power Park Module or Onshore Non-Synchronous Generating Unit if Embedded at 33kV and below (or directly connected to the Onshore Transmission System at 33kV and below) where the requirement shown in Figure 4 applies.

(b) At a Large Power Station, in the case of an Offshore Generating Unit, Offshore DC Converter and Offshore Power Park Module where an alternative reactive capability has been agreed with the Generator, as specified in CC.6.3.2(e) (iii), the voltage / Reactive Power requirement shall be specified in the Bilateral Agreement. The Reactive Power output under steady state conditions shall be fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages.
Voltage at an Onshore Grid Entry Point or User System Entry Point if Embedded (% of Nominal) at 33 kV and below

Power Factor 0.95 Lead at Rated MW output or Onshore Grid Entry Point equivalent Power Factor if connected to the Onshore Transmission System in Scotland

Power Factor 0.95 lag at Rated MW output or Onshore Grid Entry Point equivalent Power Factor if connected to the Onshore Transmission System in Scotland or optionally in Scotland for Plant with a Completion Date before 1 January 2006

Power Factor 0.9 lag at an Onshore Non-synchronous Generating Unit or Onshore Power Park Unit Terminals

Figure 4

CC.6.3.5 It is an essential requirement that the National Electricity 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 NGET will state in the Bilateral Agreement whether or not a Black Start Capability is required.

Control Arrangements

CC.6.3.6 (a) Each:

(i) Offshore Generating Unit in a Large Power Station or Onshore Generating Unit; or,

(ii) Onshore DC Converter with a Completion Date on or after 1 April 2005 or Offshore DC Converter at a Large Power Station; or,

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

(iv) Onshore 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 50MW or more); or,

(v) Offshore Power Park Module in a Large Power Station with a Registered Capacity of 50MW or more;

must be capable of contributing to Frequency control by continuous modulation of Active Power supplied to the National Electricity Transmission System or the User System in which it is Embedded. For the avoidance of doubt each OTSDUW DC Converter shall provide each User in respect of its Offshore Power Stations connected to and/or using an Offshore Transmission System a continuous signal indicating the real time Frequency measured at the Transmission Interface Point.

(b) Each:

(i) Onshore Generating Unit; or,

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

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

(iv) **Onshore Power Park Module** in Scotland irrespective of **Completion Date**; or,

(v) **Offshore Generating Unit** at a **Large Power Station**, **Offshore DC Converter** at a **Large Power Station** or **Offshore Power Park Module** at a **Large Power Station** which provides a reactive range beyond the minimum requirements specified in CC.6.3.2(e) (iii); or,

(vi) **OTSDUW Plant and Apparatus** at a **Transmission Interface Point**

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

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CC.6.3.7  

(a) Each **Generating Unit**, **DC Converter** or **Power Park Module** (excluding **Onshore Power Park Modules** in Scotland with a **Completion Date** before 1 July 2004 or **Onshore Power Park Modules** in a **Power Station** in Scotland with a **Registered Capacity** less than 50MW or **Offshore Power Park Modules** in a **Large Power Station** located **Offshore** with a **Registered Capacity** less than 50MW) 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). In the case of a **Power Park Module** the **Frequency** or speed control device(s) may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both. The **Frequency** control device(s) (or speed governor(s)) 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 **NGET** by the **Generator or DC Converter Station** owner or, in the case of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded DC Converter Station** not subject to a **Bilateral Agreement**, the relevant **Network Operator**:

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

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

(iii) in the case of an **Embedded Development**, within 28 days of entry into the **Embedded Development Agreement** (or such later time as agreed with **NGET**); or

(iv) as 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;

(iii) the Frequency control device (or speed governor) must be capable of being set so that it operates with an overall speed Droop of between 3% and 5%. For the avoidance of doubt, in the case of a Power Park Module the speed Droop should be equivalent of a fixed setting between 3% and 5% applied to each Power Park Unit in service;

(iii) in the case of all Generating Units, DC Converter or Power Park Module 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 NGET 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 Onshore Generating Unit and/or CCGT Module which has a Completion Date after 1 January 2001 in England and Wales, and after 1 April 2005 in Scotland, must be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix 3.

(ii) Each DC Converter at a DC Converter Station which has a Completion Date on or after 1 April 2005 and each Offshore DC Converter at a Large Power Station must be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix 3.

(iii) Each Onshore 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 Onshore 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 50MW or more) must be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix 3.

(v) Each Offshore Generating Unit in a Large Power Station must be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix 3.

(vi) Each Offshore Power Park Module in a Large Power Station with a Registered Capacity of 50 MW or greater, must be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix 3.

(vii) Subject to the requirements of CC.6.3.7(e), Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters in a Large Power Station shall comply with the requirements of CC.6.3.7. Generators should be aware that Section K of the STC
places requirements on Offshore Transmission Licensees which utilise a Transmission DC Converter as part of their Offshore Transmission System to make appropriate provisions to enable Generators to fulfil their obligations.

(viii) Each OTSDUW DC Converter must be capable of providing a continuous signal indicating the real time frequency measured at the Interface Point to the Offshore Grid Entry Point.

(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) Onshore 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 (BC3.5.2) operation shall apply; or

(iv) Onshore Power Park Modules in operation in Scotland before 1 January 2006 for whom only the requirements of Limited Frequency Sensitive Mode (BC3.5.2) operation shall apply; or

(v) Onshore 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; or

(vi) Offshore Power Park Modules which are in a Large Power Station with a Registered Capacity less than 50MW for whom only the requirements of Limited Frequency Sensitive Mode (BC3.5.2) operation shall apply; or

Excitation and Voltage Control Performance Requirements

CC.6.3.8 (a) Excitation and voltage control performance requirements applicable to Onshore Generating Units, Onshore Power Park Modules, Onshore DC Converters and OTSDUW Plant and Apparatus.

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

(ii) In respect of Onshore Synchronous Generating Units with a Completion Date before 1 January 2009, the requirements for excitation control facilities, including Power System Stabilisers, where in NGET’s view these are necessary for system reasons, will be specified in the Bilateral Agreement. If any Modification to the excitation control facilities of such Onshore Synchronous Generating Units is made on or after 1 January 2009 the requirements that shall apply may be specified in the Bilateral Agreement as varied. To the extent that the Bilateral Agreement does not specify, the requirements given or referred to in CC.A.6 shall apply. The performance requirements for a continuously acting automatic excitation control system that shall be complied with by the User in respect of such Onshore Synchronous Generating Units with a Completion Date on or after 1 January 2009 are given or referred to in CC.A.6. Reference is made to on-load commissioning witnessed by NGET in BC2.11.2.

(iii) In the case of an Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus at the Interface Point 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 Onshore Grid Entry Point or User System Entry Point or in the case of OTSDUW Plant and Apparatus at the Interface Point without instability over the entire operating range of the Onshore Non-Synchronous Generating Unit.
Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus. Any Plant or Apparatus used in the provisions of such voltage control within an Onshore Power Park Module may be located at the Power Park Unit terminals, an appropriate intermediate busbar or the Connection Point. OTSDUW Plant and Apparatus used in the provision of such voltage control may be located at the Offshore Grid Entry Point, an appropriate intermediate busbar or at the Interface Point. In the case of an Onshore Power Park Module in Scotland with a Completion Date before 1 January 2009, voltage control may be at the Power Park Unit terminals, an appropriate intermediate busbar or the Connection Point as specified in the Bilateral Agreement. When operating below 20% Rated MW the automatic control system may continue to provide voltage control utilising any available reactive capability. If voltage control is not being provided 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 CC.6.3.2 (c).

(iv) The performance requirements for a continuously acting automatic voltage control system in respect of Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters with a Completion Date before 1 January 2009 will be specified in the Bilateral Agreement. If any Modification to the continuously acting automatic voltage control system of such Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters is made on or after 1 January 2009 the requirements that shall apply may be specified in the Bilateral Agreement as varied. To the extent that the Bilateral Agreement does not specify, the requirements given or referred to in CC.A.7 shall apply. The performance requirements for a continuously acting automatic voltage control system that shall be complied with by the User in respect of Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters or OTSDUW Plant and Apparatus at the Interface Point with a Completion Date on or after 1 January 2009 are given or referred to in CC.A.7.

(v) Unless otherwise required for testing in accordance with OC5.A.2, the automatic excitation control system of an Onshore Synchronous Generating Unit shall always be operated such that it controls the Onshore Synchronous Generating Unit terminal voltage to a value that is

- equal to its rated value; or
- only where provisions have been made in the Bilateral Agreement, greater than its rated value.

(vi) In particular, other control facilities, including constant Reactive Power output control modes and constant Power 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 the Bilateral Agreement records otherwise. Operation of such control facilities will be in accordance with the provisions contained in BC2.

(b) Excitation and voltage control performance requirements applicable to Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station.

A continuously acting automatic control system is required to provide either:

(i) control of Reactive Power (as specified in CC.6.3.2(e) (i) (ii)) at the Offshore Grid Entry Point without instability over the entire operating range of the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module. The performance requirements for this automatic control system will be specified in the Bilateral Agreement or;

(ii) where an alternative reactive capability has been specified in the Bilateral Agreement, in accordance with CC.6.3.2 (e) (iii), the Offshore Generating Unit,
Offshore Power Park Module or Offshore DC Converter will be required to control voltage and / or Reactive Power without instability over the entire operating range of the Offshore Generating Unit, Offshore Power Park Module or Offshore DC Converter. The performance requirements of the control system will be specified in the Bilateral Agreement.

In addition to CC.6.3.8(b) (i) and (ii) the requirements for excitation control facilities, including Power System Stabilisers, where in NGET’s view these are necessary for system reasons, will be specified in the Bilateral Agreement. Reference is made to on-load commissioning witnessed by NGET in BC2.11.2.

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 National Electricity Transmission System or User System located Onshore 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, Power Park Module or transformer resulting from OTSDUW 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 National Electricity 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, OTSDUW Plant and Apparatus, 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 NGET has agreed to any Frequency-level relays and/or rate-of-change-of-Frequency relays which will trip such Generating Unit, DC Converter, OTSDUW Plant and Apparatus, Power Park Module and any constituent element within this Frequency range, under the Bilateral Agreement.

Generators (including in respect of OTSDUW Plant and Apparatus) and DC Converter Station owners will be responsible for protecting all their Generating Units (and OTSDUW Plant and Apparatus), 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.
Fault Ride Through

This section sets out the fault ride through requirements on Generating Units, Power Park Modules, DC Converters and OTSDUW Plant and Apparatus. Onshore Generating Units, Offshore Power Park Modules, Offshore DC Converters (including Embedded Medium Power Stations and Embedded DC Converter Stations not subject to a Bilateral Agreement and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)) and OTSDUW Plant and Apparatus are required to operate through System faults and disturbances as defined in CC.6.3.15.1 (a), CC.6.3.15.1 (b) and CC.6.3.15.3. Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station shall have the option of meeting either:

(i) CC.6.3.15.1 (a), CC.6.3.15.1 (b) and CC.6.3.15.3, or:

(ii) CC.6.3.15.2 (a), CC.6.3.15.2 (b) and CC.6.3.15.3

Offshore Generators and Offshore DC Converter owners, should notify NGET which option they wish to select within 28 days (or such longer period as NGET may agree, in any event this being no later than 3 months before the Completion Date of the offer for a final CUSC Contract which would be made following the appointment of the Offshore Transmission Licensee).

Fault Ride through applicable to Generating Units, Power Park Modules and DC Converters and OTSDUW Plant and Apparatus

(a) Short circuit faults on the Onshore Transmission System (which may include an Interface Point) 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 and OTSDUW Plant and Apparatus 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, OTSDUW Plant and Apparatus, and for Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment, for a close-up solid three-phase short circuit fault or any unbalanced short circuit fault on the Onshore Transmission System (including in respect of OTSDUW Plant and Apparatus, the Interface Point) 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 on the Onshore Transmission System to 90% may take longer than 140ms as illustrated in Appendix 4A Figures CC.A.4A.1 (a) and (b). It should be noted that in the case of an Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a fault on the Onshore Transmission System. The fault will affect the level of Active Power that can be transferred to the Offshore Transmission System and therefore subject the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.

(ii) Each Generating Unit, Power Park Module and OTSDUW Plant and Apparatus, shall be designed such that upon both clearance of the fault on the Onshore Transmission System as detailed in CC.6.3.15.1 (a) (i) and within 0.5 seconds of the restoration of the voltage at the Onshore Grid Entry Point (for Offshore Generating Units or Offshore Power Park Modules) or Interface Point (for Offshore Generating Units, Offshore Power Park Modules or OTSDUW Plant and Apparatus) 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 or in the case of OTSDUW Plant and Apparatus, Active Power transfer capability, shall be restored to at least 90% of the level available immediately before the fault. Once the Active Power output, or in the case of OTSDUW Plant and Apparatus, Active Power transfer capability, has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant

- the oscillations are adequately damped

During the period of the fault as detailed in CC.6.3.15.1 (a) (i) for which the voltage at the Grid Entry Point (or Interface Point in the case of OTSDUW Plant and Apparatus) is outside the limits specified in CC.6.1.4, each Generating Unit or Power Park Module or OTSDUW Plant and Apparatus shall generate maximum reactive current without exceeding the transient rating limit of the Generating Unit, OTSDUW Plant and Apparatus or Power Park Module and / or any constituent Power Park Unit or reactive compensation equipment. For Plant and Apparatus installed on or after 1 December 2017, switched reactive compensation equipment (such as mechanically switched capacitors and reactors) shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery.

(iii) Each DC Converter shall be designed to meet the Active Power recovery characteristics (and OTSDUW DC Converter shall be designed to meet the Active Power transfer capability at the Interface Point) as specified in the Bilateral Agreement upon clearance of the fault on the Onshore Transmission System as detailed in CC.6.3.15.1 (a) (i).

(b) Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration

(1b) Requirements applicable to Synchronous Generating Units subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.1 (a) each Synchronous Generating Unit, each with a Completion Date on or after 1 April 2005 shall:

(i) remain transiently stable and connected to the System without tripping of any Synchronous Generating Unit for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure 5a. Appendix 4A and Figures CC.A.4A.3.2 (a), (b) and (c) provide an explanation and illustrations of Figure 5a; and,
(ii) provide Active Power output at the Grid Entry Point, during Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5a, at least in proportion to the retained balanced voltage at the Onshore Grid Entry Point (for Onshore Synchronous Generating Units) or Interface Point (for Offshore Synchronous Generating Units) (or the retained balanced voltage at the User System Entry Point if Embedded) and shall generate maximum reactive current (where the voltage at the Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Synchronous Generating Unit and,

(iii) restore Active Power output following Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5a, within 1 second of restoration of the voltage to 1.0p.u of the nominal voltage at the:

- Onshore Grid Entry Point for directly connected Onshore Synchronous Generating Units or,
- Interface Point for Offshore Synchronous Generating Units or,
- User System Entry Point for Embedded Onshore Synchronous Generating Units or,
- User System Entry Point for Embedded Medium Power Stations not subject to a Bilateral Agreement which comprise Synchronous Generating Units and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)

to at least 90% of the level available immediately before the occurrence of the dip. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

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

(2b) Requirements applicable to OTSDUW Plant and Apparatus and Power Park Modules subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration
In addition to the requirements of CC.6.3.15.1 (a) each OTSDUW Plant and Apparatus or each 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 OTSDUW Plant and Apparatus, or Power Park Module and / or any constituent Power Park Unit, for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure 5b. Appendix 4A and Figures CC.A.4A.3.4 (a), (b) and (c) provide an explanation and illustrations of Figure 5b; and,

(ii) provide Active Power output at the Grid Entry Point or in the case of an OTSDUW, Active Power transfer capability at the Transmission Interface Point, during Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5b, at least in proportion to the retained balanced voltage at the Onshore Grid Entry Point (for Onshore Power Park Modules) or Interface Point (for OTSDUW Plant and Apparatus and Offshore Power Park Modules) (or the retained balanced voltage at the User System Entry Point if Embedded) except in the case of a Non-Synchronous Generating Unit or OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source or in the case of OTSDUW Active Power transfer capability in the time range in Figure 5b that restricts the Active Power output or in the case of an OTSDUW Active Power transfer capability below this level and shall generate maximum reactive current (where the voltage at the Grid Entry Point, or in the case of an OTSDUW Plant and Apparatus, the Interface Point voltage, is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the OTSDUW Plant and Apparatus or Power Park Module and any constituent Power Park Unit; and,

(iii) restore Active Power output (or, in the case of OTSDUW, Active Power transfer capability), following Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5b, within 1 second of restoration of the voltage at the:

Onshore Grid Entry Point for directly connected Onshore Power Park Modules or,
Interface Point for OTSDUW Plant and Apparatus and Offshore Power Park Modules or,

User System Entry Point for Embedded Onshore Power Park Modules or,

User System Entry Point for Embedded Medium Power Stations which comprise Power Park Modules not subject to a Bilateral Agreement and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)

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, OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 5b that restricts the Active Power output or, in the case of OTSDUW, Active Power transfer capability below this level. Once the Active Power output or, in the case of OTSDUW, Active Power transfer capability has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

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

CC.6.3.15.2 Fault Ride Through applicable to Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station who choose to meet the fault ride through requirements at the LV side of the Offshore Platform

(a) Requirements on Offshore Generating Units, Offshore Power Park Modules and Offshore DC Converters to withstand voltage dips on the LV Side of the Offshore Platform for up to 140ms in duration as a result of faults and / or voltage dips on the Onshore Transmission System operating at Supergrid Voltage

(i) Each Offshore Generating Unit, Offshore DC Converter, or Offshore Power Park Module and any constituent Power Park Unit thereof shall remain transiently stable and connected to the System without tripping of any Offshore Generating Unit, or Offshore DC Converter or Offshore Power Park Module and / or any constituent Power Park Unit or, in the case of Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment, for any balanced or unbalanced voltage dips on the LV Side of the Offshore Platform whose profile is anywhere on or above the heavy black line shown in Figure 6. For the avoidance of doubt, the profile beyond 140ms in Figure 6 shows the minimum recovery in voltage that will be seen by the generator following clearance of the fault at 140ms. Appendix 4B and Figures CC.A.4B.2 (a) and (b) provide further illustration of the voltage recovery profile that may be seen. It should be noted that in the case of an Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a fault on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Offshore Transmission System and therefore subject the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.
Figure 6

$V/V_N$ is the ratio of the actual voltage on one or more phases at the LV Side of the Offshore Platform to the nominal voltage of the LV Side of the Offshore Platform.

(ii) Each Offshore Generating Unit, or Offshore Power Park Module and any constituent Power Park Unit thereof shall provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 6, at least in proportion to the retained voltage at the LV Side of the Offshore Platform except in the case of an Offshore Non-Synchronous Generating Unit or Offshore Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 6 that restricts the Active Power output below this level and shall generate maximum reactive current without exceeding the transient rating limits of the Offshore Generating Unit or Offshore Power Park Module and any constituent Power Park Unit or, in the case of Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped

and;

(iii) Each Offshore DC Converter shall be designed to meet the Active Power recovery characteristics as specified in the Bilateral Agreement upon restoration of the voltage at the LV Side of the Offshore Platform.

(b) Requirements of Offshore Generating Units, Offshore Power Park Modules, to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.

(1b) Requirements applicable to Offshore Synchronous Generating Units to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.2. (a) each Offshore Synchronous Generating Unit shall:
(i) remain transiently stable and connected to the System without tripping of any Offshore Synchronous Generating Unit for any balanced voltage dips on the LV side of the Offshore Platform and associated durations anywhere on or above the heavy black line shown in Figure 7a. Appendix 4B and Figures CC.A.4B.3.2 (a), (b) and (c) provide an explanation and illustrations of Figure 7a. It should be noted that in the case of an Offshore Synchronous Generating Unit which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a voltage dip on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Onshore Transmission System and therefore subject the Offshore Generating Unit, to a load rejection.

(ii) provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 7a, at least in proportion to the retained balanced or unbalanced voltage at the LV Side of the Offshore Platform and shall generate maximum reactive current (where the voltage at the Offshore Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Offshore Synchronous Generating Unit and,

(iii) within 1 second of restoration of the voltage to 1.0p.u of the nominal voltage at the LV Side of the Offshore Platform, restore Active Power to at least 90% of the Offshore Synchronous Generating Unit’s immediate pre-disturbed value, unless there has been a reduction in the Intermittent Power Source in the time range in Figure 7a that restricts the Active Power output below this level. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped

(2b) Requirements applicable to Offshore Power Park Modules to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.
In addition to the requirements of CC.6.3.15.2. (a) each Offshore Power Park Module and / or any constituent Power Park Unit, shall:

(i) remain transiently stable and connected to the System without tripping of any Offshore Power Park Module and / or any constituent Power Park Unit, for any balanced voltage dips on the LV side of the Offshore Platform and associated durations anywhere on or above the heavy black line shown in Figure 7b. Appendix 4B and Figures CC.A.4B.5. (a), (b) and (c) provide an explanation and illustrations of Figure 7b. It should be noted that in the case of an Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a voltage dip on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Onshore Transmission System and therefore subject the Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.

(ii) provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 7b, at least in proportion to the retained balanced or unbalanced voltage at the LV Side of the Offshore Platform except in the case of an Offshore Non-Synchronous Generating Unit or Offshore Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 7b that restricts the Active Power output below this level and shall generate maximum reactive current (where the voltage at the Offshore Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Offshore Power Park Module and any constituent Power Park Unit or reactive compensation equipment. For Plant and Apparatus installed on or after 1 December 2017, switched reactive compensation equipment (such as mechanically switched capacitors and reactors) shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery; and,

(iii) within 1 second of the restoration of the voltage at the LV Side of the Offshore Platform (to the minimum levels specified in CC.6.1.4) restore Active Power to at least 90% of the Offshore Power Park Module's immediate pre-disturbed value, unless there has been a reduction in the Intermittent Power Source in the time range in Figure 7b that restricts the Active Power output below this level. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:
the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant.

- the oscillations are adequately damped

CC.6.3.15.3 Other Requirements

(i) In the case of a Power Park Module (comprising of wind-turbine generator units), the requirements in CC.6.3.15.1 and CC.6.3.15.2 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, OTSDUW Plant and Apparatus or Power Park Module with a Completion Date after 1 April 2005 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 Onshore Transmission System operating at Supergrid Voltage.

(iii) In the case of an Onshore Power Park Module in Scotland with a Completion Date before 1 January 2004 and a Registered Capacity less than 30MW the requirements in CC.6.3.15.1 (a) do not apply. In the case of an Onshore 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.6.3.15.1 (a) are relaxed from the minimum Onshore Transmission System Supergrid Voltage of zero to a minimum Onshore Transmission System Supergrid Voltage of 15% of nominal. In the case of an Onshore 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.6.3.15.1 (a) are relaxed from the minimum Onshore Transmission System Supergrid Voltage of zero to a minimum Onshore Transmission System Supergrid Voltage of 15% of nominal.

(iv) To avoid unwanted island operation, Non-Synchronous Generating Units in Scotland (and those directly connected to a Scottish Offshore Transmission System), Power Park Modules in Scotland (and those directly connected to a Scottish Offshore Transmission System), or OTSDUW Plant and Apparatus with an Interface Point 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 Onshore Connection Point or Onshore User System Entry Point or Offshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus is below 80% for more than 2.5 seconds
4. Voltage as measured at the Onshore Connection Point or Onshore User System Entry Point or Offshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus is 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 OTSDUW Plant and Apparatus or Power Park Modules.
Additional Damping Control Facilities for DC Converters

CC.6.3.16 (a) DC Converter owners, or Generators in respect of OTSDUW DC Converters or Network Operators in the case of an Embedded DC Converter Station not subject to a Bilateral Agreement must ensure that any of their Onshore DC Converters or OTSDUW DC Converters will not cause a sub-synchronous resonance problem on the Total System. Each DC Converter or OTSDUW DC Converter is required to be provided with sub-synchronous resonance damping control facilities.

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

System to Generator Operational Intertripping Scheme

CC.6.3.17 NGET may require that a System to Generator Operational Intertripping Scheme be installed as part of a condition of the connection of the Generator. Scheme specific details shall be included in the relevant Bilateral Agreement and shall, in respect of Bilateral Agreements entered into on or after 16th March 2009 include the following information:

(1) the relevant category(ies) of the scheme (referred to as Category 1 Intertripping Scheme, Category 2 Intertripping Scheme, Category 3 Intertripping Scheme and Category 4 Intertripping Scheme);

(2) the Generating Unit(s) or CCGT Module(s) or Power Park Module(s) to be either permanently armed or that can be instructed to be armed in accordance with BC2.8;

(3) the time within which the Generating Unit(s) or CCGT Module(s) or Power Park Module(s) circuit breaker(s) are to be automatically tripped;

(4) the location to which the trip signal will be provided by NGET. Such location will be provided by NGET prior to the commissioning of the Generating Unit(s) or CCGT Module(s) or Power Park Module(s).

Where applicable, the Bilateral Agreement shall include the conditions on the National Electricity Transmission System during which NGET may instruct the System to Generator Operational Intertripping Scheme to be armed and the conditions that would initiate a trip signal.

CC.6.3.18 The time within which the Generating Unit(s) or CCGT Module or Power Park Module circuit breaker(s) need to be automatically tripped is determined by the specific conditions local to the Generator. This ‘time to trip’ (defined as time from provision of the trip signal by NGET to the specified location, to circuit breaker main contact opening) can typically range from 100ms to 10sec. A longer time to trip may allow the initiation of an automatic reduction in the Generating Unit(s) or CCGT Module(s) or Power Park Module(s) output prior to the automatic tripping of the Generating Unit(s) or CCGT Module(s) or Power Park Module(s) circuit breaker. Where applicable NGET may provide separate trip signals to allow for either a longer or shorter ‘time to trip’ to be initiated.

CC.6.4 General Network Operator And Non-Embedded Customer Requirements

CC.6.4.1 This part of the Grid Code describes the technical and design criteria and performance requirements for Network Operators and Non-Embedded Customers.
Neutral Earthing

CC.6.4.2 At nominal System voltages of 132kV and above the higher voltage windings of three phase transformers and transformer banks connected to the National Electricity Transmission System 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 National Electricity Transmission System at nominal System voltages of 132kV and above.

Frequency Sensitive Relays

CC.6.4.3 As explained under OC6, each Network Operator, will make arrangements that will facilitate automatic low Frequency Disconnection of Demand (based on Annual ACS Conditions). CC.A.5.5. of Appendix 5 includes specifications of the local percentage Demand that shall be disconnected at specific frequencies. The manner in which Demand subject to low Frequency disconnection will be split into discrete MW blocks is specified in OC6.6. Technical requirements relating to Low Frequency Relays are also listed in Appendix 5.

Operational Metering

CC.6.4.4 Where NGET can reasonably demonstrate that an Embedded Medium Power Station or Embedded DC Converter Station has a significant effect on the National Electricity Transmission System, it may require the Network Operator within whose System the Embedded Medium Power Station or Embedded DC Converter Station is situated to ensure that the operational metering equipment described in CC.6.5.6 is installed such that NGET can receive the data referred to in CC.6.5.6. In the case of an Embedded Medium Power Station subject to, or proposed to be subject to a Bilateral Agreement NGET shall notify such Network Operator of the details of such installation in writing within 3 months of being notified of the application to connect under CUSC and in the case of an Embedded Medium Power Station not subject to, or not proposed to be subject to a Bilateral Agreement in writing as a Site Specific Requirement in accordance with the timescales in CUSC 6.5.5. In either case the Network Operator shall ensure that the data referred to in CC.6.5.6 is provided to NGET.

Communications Plant

CC.6.5 In order to ensure control of the National Electricity Transmission System, telecommunications between Users and NGET must (including in respect of any OTSDUW Plant and Apparatus at the OTSUA Transfer Time), if required by NGET, be established in accordance with the requirements set down below.

Control Telephony and System Telephony

CC.6.5.2 Control Telephony is the principle method by which a User’s Responsible Engineer/Operator and NGET Control Engineers speak to one another for the purposes of control of the Total System in both normal and emergency operating conditions. Control Telephony provides secure point to point telephony for routine Control Calls, priority Control Calls and emergency Control Calls.

System Telephony is an alternate method by which a User’s Responsible Engineer/Operator and NGET Control Engineers speak to one another for the purposes of control of the Total System in both normal operating conditions and where practicable, emergency operating conditions. System Telephony uses the Public Switched Telephony Network to provide telephony for Control Calls, inclusive of emergency Control Calls.

Calls made and received over Control Telephony and System Telephony may be recorded and subsequently replayed for commercial and operational reasons.

Supervisory Tones

CC.6.5.3 Control Telephony supervisory tones indicate to the calling and receiving parties dial, engaged, ringing, secondary engaged (signifying that priority may be exercised) and priority disconnect tones.
System Telephony supervisory tones indicate to the calling and receiving parties dial, engaged and ringing tones.

**Obligations in respect of Control Telephony and System Telephony**

Where NGET requires Control Telephony, Users are required to use the Control Telephony with NGET in respect of all Connection Points with the National Electricity Transmission System and in respect of all Embedded Large Power Stations and Embedded DC Converter Stations. NGET will install Control Telephony at the User’s Control Point 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.

Where in NGET’s sole opinion the installation of Control Telephony is not practicable at a User’s Control Point(s), NGET shall specify in the Bilateral Agreement whether System Telephony is required. Where System Telephony is required by NGET, the User shall ensure that System Telephony is installed.

Where System Telephony is installed, Users are required to use the System Telephony with NGET in respect of those Control Point(s) for which it has been installed. Details of and relating to the System Telephony required are contained in the Bilateral Agreement.

Where Control Telephony or System Telephony is installed, routine testing of such facilities may be required by NGET (not normally more than once in any calendar month). The User and NGET shall use reasonable endeavours to agree a test programme and where NGET requests the assistance of the User in performing the agreed test programme the User shall provide such assistance.

Control Telephony and System Telephony shall only be used for the purposes of operational voice communication between NGET and the relevant User.

Control Telephony contains emergency calling functionality to be used for urgent operational communication only. Such functionality enables NGET and Users to utilise a priority call in the event of an emergency. NGET and Users shall only use such priority call functionality for urgent operational communications.

Technical Requirements for Control Telephony and System Telephony

Detailed information on the technical interfaces and support requirements for Control Telephony applicable in NGET’s Transmission Area is provided in the Control Telephony Electrical Standard identified in the Annex to the General Conditions. Where additional information, or information in relation to Control Telephony applicable in Scotland, is requested by Users, this will be provided, where possible, by NGET.

System Telephony shall consist of a dedicated Public Switched Telephone Network telephone line that shall be installed and configured by the relevant User. NGET shall provide a dedicated free phone number (UK only), for the purposes of receiving incoming calls to NGET, which Users shall utilise for System Telephony. System Telephony shall only be utilised by the NGET Control Engineer and the User’s Responsible Engineer/Operator for the purposes of operational communications.

Operational Metering

(a) NGET 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 NGET in accordance with the terms of the Bilateral Agreement. In the case of OTSDUW, the User shall provide such SCADA outstation interface equipment and voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the SCADA outstation interface equipment as required by NGET in accordance with the terms of the Bilateral Agreement.
(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 NGET 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 and OTSDUW DC Converters**, the outputs and status indications must each be provided to NGET 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 NGET 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.

(iv) In respect of OTSDUW Plant and Apparatus, the outputs and status indications must be provided to NGET for each piece of electrical equipment. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements at the Interface Point 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 NGET 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 NGET. Details of such arrangements will be contained in the relevant Bilateral Agreements between NGET and the Generator and the Network Operator.

(d) In the case of a Power Park Module, additional energy input signals (e.g. wind speed, and wind direction) may be specified in the Bilateral Agreement. For Power Park Modules with a Completion Date on or after 1st April 2016 a Power Available signal will also be specified in the Bilateral Agreement. The signals would be used to establish the potential 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 NGET with advanced warning of excess wind speed shutdown and to determine the level of Headroom available from Power Park Modules for the purposes of calculating response and reserve. For the avoidance of doubt, the Power Available signal would be automatically provided to NGET and represent the sum of the potential output of all available and operational Power Park Units within the Power Park Module. The refresh rate of the Power Available signal shall be specified in the Bilateral Agreement.

**Instructor Facilities**

CC.6.5.7 The User shall accommodate Instructor Facilities provided by NGET for the receipt of operational messages relating to System conditions.

**Electronic Data Communication Facilities**

CC.6.5.8 (a) All BM Participants must ensure that appropriate electronic data communication facilities are in place to permit the submission of data, as required by the Grid Code, to NGET.

(b) In addition,

(1) any User that wishes to participate in the Balancing Mechanism;
(2) any BM Participant in respect of its BM Units at a Power Station where the Construction Agreement and/or a Bilateral Agreement has a Completion Date on or after 1 January 2013 and the BM Participant is required to provide all Part 1 System Ancillary Services in accordance with CC.8.1 (unless NGET has otherwise agreed)

must ensure that appropriate automatic logging devices are installed at the Control Points of its BM Units to submit data to and to receive instructions from NGET, as required by the Grid Code. For the avoidance of doubt, in the case of an Interconnector User the Control Point will be at the Control Centre of the appropriate Externally Interconnected System Operator.

(c) Detailed specifications of these required electronic facilities will be provided by NGET on request and they are listed as Electrical Standards in the Annex to the General Conditions.

Facsimile Machines

CC.6.5.9 Each User and NGET 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 NGET 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, NGET of its or their telephone number or numbers, and will notify NGET of any changes. Prior to connection to the System of the User's Plant and Apparatus NGET 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

NGET 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 permit its Gensets or DC Converters to be Synchronised to the National Electricity 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 NGET’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 NGET 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 NGET upon request.

CC.6.6 System Monitoring

CC.6.6.1 Monitoring equipment is provided on the National Electricity Transmission System to enable NGET 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 or from OTSDUW Plant and Apparatus, NGET 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.6.6.2 For all on site monitoring by NGET of witnessed tests pursuant to the CP or OC5 the User shall provide suitable test signals as outlined in OC5.A.1.

CC.6.6.2.1 The signals which shall be provided by the User to NGET for onsite monitoring shall be of the following resolution, unless otherwise agreed by NGET:

(i) 1 Hz for reactive range tests
(ii) 10 Hz for frequency control tests
(iii) 100 Hz for voltage control tests

CC.6.6.2.2 The User will provide all relevant signals for this purpose in the form of d.c. voltages within the range -10V to +10V. In exceptional circumstances some signals may be accepted as d.c. voltages within the range -60V to +60V with prior agreement between the User and NGET. All signals shall:

(i) in the case of an Onshore Power Park Module, DC Convertor Station or Synchronous Generating Unit, be suitably terminated in a single accessible location at the Generator or DC Convertor Station owner's site.
(ii) in the case of an Offshore Power Park Module and OTSDUW Plant and Apparatus, be transmitted onshore without attenuation, delay or filtering which would result in the inability to fully demonstrate the objectives of the test, or identify any potential safety or plant instability issues, and be suitably terminated in a single robust location normally located at or near the onshore Interface Point of the Offshore Transmission System to which it is connected.

CC.6.6.2.3 All signals shall be suitably scaled across the range. The following scaling would (unless NGET notify the User otherwise) be acceptable to NGET:

(a) 0MW to Registered Capacity or Interface Point Capacity 0-8V dc
(b) Maximum leading Reactive Power to maximum lagging Reactive Power -8 to 8V dc
(c) 48 – 52Hz as -8 to 8V dc
(d) Nominal terminal or connection point voltage -10% to +10% as -8 to 8V dc

CC.6.6.2.4 The User shall provide to NGET a 230V power supply adjacent to the signal terminal location.

CC.7 SITE RELATED CONDITIONS

CC.7.1 Not used.

CC.7.2 Responsibilities For Safety

CC.7.2.1 In England and Wales, any User entering and working on its Plant and/or Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site will work to the Safety Rules of NGET.
In Scotland or Offshore, any User entering and working on its Plant and/or Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site will work to the Safety Rules of the Relevant Transmission Licensee, as advised by NGET.

CC.7.2.2 NGET entering and working on Transmission Plant and/or Apparatus on a User Site will work to the User's Safety Rules. For User Sites in Scotland or Offshore, NGET shall procure that the Relevant Transmission Licensee entering and working on Transmission Plant and/or Apparatus on a User Site will work to the User's Safety Rules.

CC.7.2.3 A User may, with a minimum of six weeks notice, apply to NGET for permission to work according to that User's own Safety Rules when working on its Plant and/or Apparatus on a Transmission Site rather than those set out in CC.7.2.1. If NGET is of the opinion that the User's Safety Rules provide for a level of safety commensurate with those set out in CC.7.2.1, NGET will notify the User, in writing, that, with effect from the date requested by the User, the User may use its own Safety Rules when working on its Plant and/or Apparatus on the Transmission Site. For a Transmission Site in Scotland or Offshore, in forming its opinion, NGET will seek the opinion of the Relevant Transmission Licensee. Until receipt of such written approval from NGET, the User will continue to use the Safety Rules as set out in CC.7.2.1.

CC.7.2.4 In the case of a User Site in England and Wales, NGET may, with a minimum of six weeks notice, apply to a User for permission to work according to NGET’s Safety Rules when working on Transmission Plant and/or Apparatus on that User Site, rather than the User’s Safety Rules. If the User is of the opinion that NGET’s Safety Rules provide for a level of safety commensurate with that of that User’s Safety Rules, it will notify NGET, in writing, that, with the effect from the date requested by NGET, NGET may use its own Safety Rules when working on its Transmission Plant and/or Apparatus on that User Site. Until receipt of such written approval from the User, NGET shall continue to use the User’s Safety Rules.

In the case of a User Site in Scotland or Offshore, NGET may, with a minimum of six weeks notice, apply to a User for permission for the Relevant Transmission Licensee to work according to the Relevant Transmission Licensee’s Safety Rules when working on Transmission Plant and/or Apparatus on that User Site, rather than the User’s Safety Rules. If the User is of the opinion that the Relevant Transmission Licensee’s Safety Rules, provide for a level of safety commensurate with that of that User’s Safety Rules, it will notify NGET, in writing, that, with effect from the date requested by NGET, that the Relevant Transmission Licensee may use its own Safety Rules when working on its Transmission Plant and/or Apparatus on that User’s Site. Until receipt of such written approval from the User, NGET shall procure that the Relevant Transmission Licensee shall continue to use the User’s Safety Rules.

CC.7.2.5 For a Transmission Site in England and Wales, if NGET gives its approval for the User’s Safety Rules to apply to the User when working on its Plant and/or Apparatus, that does not imply that the User’s Safety Rules will apply to entering the Transmission Site and access to the User’s Plant and/or Apparatus on that Transmission Site. Bearing in mind NGET’s responsibility for the whole Transmission Site, entry and access will always be in accordance with NGET’s site access procedures. For a User Site in England and Wales, if the User gives its approval for NGET’s Safety Rules to apply to NGET when working on its Plant and Apparatus, that does not imply that NGET’s Safety Rules will apply to entering the User Site, and access to the Transmission Plant and Apparatus on that User Site. Bearing in mind the User’s responsibility for the whole User Site, entry and access will always be in accordance with the User's site access procedures.
For a Transmission Site in Scotland or Offshore, if NGET gives its approval for the User's Safety Rules to apply to the User when working on its Plant and/or Apparatus, that does not imply that the User's Safety Rules will apply to entering the Transmission Site and access to the User's Plant and/or Apparatus on that Transmission Site. Bearing in mind the Relevant Transmission Licensee's responsibility for the whole Transmission Site, entry and access will always be in accordance with the Relevant Transmission Licensee's site access procedures. For a User Site in Scotland or Offshore, if the User gives its approval for Relevant Transmission Licensee Safety Rules to apply to the User when working on its Plant and/or Apparatus, that does not imply that the User's Safety Rules will apply to entering the Transmission Site and access to the User's Plant and/or Apparatus on that User Site. Bearing in mind the User's responsibility for the whole User Site, entry and access will always be in accordance with the User's site access procedures.

CC.7.2.6

For User Sites in England and Wales, Users shall notify NGET of any Safety Rules that apply to NGET's staff working on User Sites. For Transmission Sites in England and Wales, NGET shall notify Users of any Safety Rules that apply to the User's staff working on the Transmission Site.

For User Sites in Scotland or Offshore, Users shall notify NGET of any Safety Rules that apply to the Relevant Transmission Licensee's staff working on User Sites. For Transmission Sites in Scotland or Offshore NGET shall procure that the Relevant Transmission Licensee shall notify Users of any Safety Rules that apply to the User's staff working on the Transmission Site.

CC.7.2.7

Each Site Responsibility Schedule must have recorded on it the Safety Rules which apply to each item of Plant and/or Apparatus.

CC.7.2.8

In the case of OTSUA a User Site or Transmission Site shall, for the purposes of this CC.7.2, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

CC.7.3

Site Responsibility Schedules

CC.7.3.1
In order to inform site operational staff and NGET Control Engineers of agreed responsibilities for Plant and/or Apparatus at the operational interface, a Site Responsibility Schedule shall be produced for Connection Sites (and in the case of OTSUA, until the OTSUA Transfer Time, Interface Sites) in England and Wales for NGET and Users with whom they interface, and for Connection Sites (and in the case of OTSUA, until the OTSUA Transfer Time, Interface Sites) in Scotland or Offshore for NGET, the Relevant Transmission Licensee and Users with whom they interface.

CC.7.3.2
The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix 1.

CC.7.4

Operation And Gas Zone Diagrams

Operation Diagrams

CC.7.4.1
An Operation Diagram shall be prepared for each Connection Site at which a Connection Point exists (and in the case of OTSDUW Plant and Apparatus, by User's for each Interface Point) using, where appropriate, the graphical symbols shown in Part 1A of Appendix 2. Users should also note that the provisions of OC11 apply in certain circumstances.
CC.7.4.2 The Operation Diagram shall include all HV Apparatus and the connections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in OC11. At those Connection Sites (or in the case of OTSDUW Plant and Apparatus, Interface Points) where gas-insulated metal enclosed switchgear and/or other gas-insulated HV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects gas-zone boundaries. The nomenclature used shall conform with that used on the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, Interface Point and circuit). The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of HV Apparatus and related Plant.

CC.7.4.3 A non-exhaustive guide to the types of HV Apparatus to be shown in the Operation Diagram is shown in Part 2 of Appendix 2, together with certain basic principles to be followed unless equivalent principles are approved by NGET.

Gas Zone Diagrams

CC.7.4.4 A Gas Zone Diagram shall be prepared for each Connection Site at which a Connection Point (and in the case of OTSDUW Plant and Apparatus, by User's for an Interface Point) exists where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised. They shall use, where appropriate, the graphical symbols shown in Part 1B of Appendix 2.

CC.7.4.5 The nomenclature used shall conform with that used in the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, relevant Interface Point and circuit).

CC.7.4.6 The basic principles set out in Part 2 of Appendix 2 shall be followed in the preparation of Gas Zone Diagrams unless equivalent principles are approved by NGET.

Preparation of Operation and Gas Zone Diagrams for Users' Sites and Transmission Interface Sites

CC.7.4.7 In the case of a User Site, the User shall prepare and submit to NGET, an Operation Diagram for all HV Apparatus on the User side of the Connection Point (and in the case of OTSDUW Plant and Apparatus, on what will be the Offshore Transmission side of the Connection Point and the Interface Point) and NGET shall provide the User with an Operation Diagram for all HV Apparatus on the Transmission side of the Connection Point (and in the case of OTSDUW Plant and Apparatus on what will be the Onshore Transmission side of the Interface Point, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement.

CC.7.4.8 The User will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram and NGET Operation Diagram, a composite Operation Diagram for the complete Connection Site (and in the case of OTSDUW Plant and Apparatus, Interface Point), also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

CC.7.4.9 The provisions of CC.7.4.7 and CC.7.4.8 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

Preparation of Operation and Gas Zone Diagrams for Transmission Sites

CC.7.4.10 In the case of a Transmission Site, the User shall prepare and submit to NGET an Operation Diagram for all HV Apparatus on the User side of the Connection Point, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

CC.7.4.11 NGET will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram, a composite Operation Diagram for the complete Connection Site, also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

CC.7.4.12 The provisions of CC.7.4.10 and CC.7.4.11 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.
CC.7.4.13  Changes to Operation and Gas Zone Diagrams

When NGET has decided that it wishes to install new HV Apparatus or it wishes to change the existing numbering or nomenclature of Transmission HV Apparatus at a Transmission Site, NGET will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to each such User a revised Operation Diagram of that Transmission Site, incorporating the new Transmission HV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be. OC11 is also relevant to certain Apparatus.

When a User has decided that it wishes to install new HV Apparatus, or it wishes to change the existing numbering or nomenclature of its HV Apparatus at its User Site, the User will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to NGET a revised Operation Diagram of that User Site incorporating the new User HV Apparatus to be installed and its numbering and nomenclature or the changes as the case may be. OC11 is also relevant to certain Apparatus.

The provisions of CC.7.4.13.1 and CC.7.4.13.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is installed.

Validity

(a) The composite Operation Diagram prepared by NGET or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Connection Site, as soon as reasonably practicable, between NGET and the User, to endeavour to resolve the matters in dispute.

(b) The composite Operation Diagram prepared by NGET or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between NGET and the User, to endeavour to resolve the matters in dispute.

(c) An equivalent rule shall apply for Gas Zone Diagrams where they exist for a Connection Site.

CC.7.4.15  In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this CC.7.4, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System and references to HV Apparatus in this CC.7.4 shall include references to HV OTSUA.

CC.7.5  Site Common Drawings

CC.7.5.1  Site Common Drawings will be prepared for each Connection Site (and in the case of OTSUDUW, each Interface Point) and will include Connection Site (and in the case of OTSUDUW, Interface Point) layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

Preparation of Site Common Drawings for a User Site and Transmission Interface Site

In the case of a User Site, NGET shall prepare and submit to the User, Site Common Drawings for the Transmission side of the Connection Point (and in the case of OTSUDUW Plant and Apparatus, on what will be the Onshore Transmission side of the Interface Point,) and the User shall prepare and submit to NGET, Site Common Drawings for the User side of the Connection Point (and in the case of OTSUDUW, on what will be the Offshore Transmission side of the Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.
The User will then prepare, produce and distribute, using the information submitted on the Transmission Site Common Drawings, Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

Preparation of Site Common Drawings for a Transmission Site

In the case of a Transmission Site, the User will prepare and submit to NGET Site Common Drawings for the User side of the Connection Point in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

NGET will then prepare, produce and distribute, using the information submitted in the User's Site Common Drawings, Site Common Drawings for the complete Connection Site in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

When a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:

(a) if it is a User Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and

(b) if it is a Transmission Site, as soon as reasonably practicable, prepare and submit to NGET revised Site Common Drawings for the User side of the Connection Point (and in the case of OTSDUW, Interface Point) and NGET will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the User's Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in the User's reasonable opinion the change can be dealt with by it notifying NGET in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

When NGET becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:

(a) if it is a Transmission Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and

(b) if it is a User Site, as soon as reasonably practicable, prepare and submit to the User revised Site Common Drawings for the Transmission side of the Connection Point (and in the case of OTSDUW, Interface Point) and the User will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the Transmission Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in NGET's reasonable opinion the change can be dealt with by it notifying the User in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

Validity

(a) The Site Common Drawings for the complete Connection Site prepared by the User or NGET, as the case may be, will be the definitive Site Common Drawings for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the Site, as soon as reasonably practicable, between NGET and the User, to endeavour to resolve the matters in dispute.
(b) The Site Common Drawing prepared by NGET or the User, as the case may be, will be the definitive Site Common Drawing for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between NGET and the User, to endeavour to resolve the matters in dispute.

CC.7.5.9 In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this CC.7.5, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

CC.7.6 Access
CC.7.6.1 The provisions relating to access to Transmission Sites by Users, and to Users’ Sites by Transmission Licensees, are set out in each Interface Agreement (or in the case of Interfaces Sites prior to the OTSUA Transfer Time agreements in similar form) with, for Transmission Sites in England and Wales, NGET and each User, and for Transmission Sites in Scotland and Offshore, the Relevant Transmission Licensee and each User.

CC.7.6.2 In addition to those provisions, where a Transmission Site in England and Wales contains exposed HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by NGET and where a Transmission Site in Scotland or Offshore contains exposed HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by the Relevant Transmission Licensee.

CC.7.6.3 The procedure for applying for an Authority for Access is contained in the Interface Agreement.

CC.7.7 Maintenance Standards
CC.7.7.1 It is the User’s responsibility to ensure that all its Plant and Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site is tested and maintained adequately for the purpose for which it is intended, and to ensure that it does not pose a threat to the safety of any Transmission Plant, Apparatus or personnel on the Transmission Site. NGET will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus at any time.

CC.7.7.2 For User Sites in England and Wales, NGET has a responsibility to ensure that all Transmission Plant and Apparatus on a User Site is tested and maintained adequately for the purposes for which it is intended and to ensure that it does not pose a threat to the safety of any User’s Plant, Apparatus or personnel on the User Site.

For User Sites in Scotland and Offshore, NGET shall procure that the Relevant Transmission Licensee has a responsibility to ensure that all Transmission Plant and Apparatus on a User Site is tested and maintained adequately for the purposes for which it is intended and to ensure that it does not pose a threat to the safety of any User’s Plant, Apparatus or personnel on the User Site.

The User will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus on its User Site at any time.

CC.7.8 Site Operational Procedures
CC.7.8.1 NGET and Users with an interface with NGET, must make available staff to take necessary Safety Precautions and carry out operational duties as may be required to enable work/testing to be carried out and for the operation of Plant and Apparatus (including, prior to the OTSUA Transfer Time, any OTSUA) connected to the Total System.
Generators and DC Converter Station owners shall provide a Control Point in respect of each Power Station directly connected to the National Electricity Transmission System and Embedded Large Power Station or DC Converter Station to receive an 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. The Control Point shall be continuously manned except where the Bilateral Agreement in respect of such Embedded Power Station specifies that compliance with BC2 is not required, where the Control Point shall be manned between the hours of 0800 and 1800 each day.

ANCILLARY SERVICES

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

(a) Generators in respect of Large Power Stations are obliged to provide (except Generators in respect of Large Power Stations which have a Registered Capacity of less than 50MW and comprise Power Park Modules); and,

(b) Generators in respect of Large Power Stations with a Registered Capacity of less than 50MW and comprise Power Park Modules are obliged to provide in respect of Reactive Power only; and,

(c) DC Converter Station owners are obliged to have the capability to supply; and

(d) Generators in respect of Medium Power Stations (except Embedded Medium Power Stations) are obliged to provide in respect of Reactive Power only:

and Part 2 lists the System Ancillary Services which Generators will provide only if agreement to provide them is reached with NGET:

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)

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

Part 2

(c) Frequency Control by means of Fast Start - CC.6.3.14

(d) Black Start Capability - CC.6.3.5

(e) System to Generator Operational Intertripping
Commercial Ancillary Services

Other Ancillary Services are also utilised by NGET in operating the Total System if these have been agreed to be provided by a User (or other person) under an Ancillary Services Agreement or under a Bilateral Agreement, with payment being dealt with under an Ancillary Services Agreement or in the case of Externally Interconnected System Operators or Interconnector Users, under any other agreement (and in the case of Externally Interconnected System Operators and Interconnector Users includes ancillary services equivalent to or similar to System Ancillary Services) ("Commercial Ancillary Services"). The capability for these Commercial Ancillary Services is set out in the relevant Ancillary Services Agreement or Bilateral Agreement (as the case may be).
APPENDIX 1 - SITE RESPONSIBILITY SCHEDULES

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 (which in the context of this CC shall include, Interface Sites until the OTSUA Transfer Time) the following Site Responsibility Schedules shall be drawn up using the relevant proforma attached or with such variations as may be agreed between NGET and Users, but in the absence of agreement the relevant proforma attached will be used. In addition, in the case of OTSDUW Plant and Apparatus, and in readiness for the OTSUA Transfer Time, the User shall provide NGET with the necessary information such that Site Responsibility Schedules in this form can be prepared by the Relevant Transmission Licensees for the Transmission Interface Site:

(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.

New Connection Sites

CC.A.1.1.2 In the case of a new Connection Site each Site Responsibility Schedule for a Connection Site shall be prepared by NGET in consultation with relevant Users at least 2 weeks prior to the Completion Date (or, where the OTSUA is to become Operational prior to the OTSUA Transfer Time, an alternative date) under the Bilateral Agreement and/or Construction Agreement for that Connection Site (which may form part of a Complex). In the case of a new Interface Site where the OTSUA is to become Operational prior to the OTSUA Transfer Time each Site Responsibility Schedule for an Interface Site shall be prepared by NGET in consultation with relevant Users at least 2 weeks prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement for that Interface Site (which may form part of a Complex) (and references to and requirements placed on “Connection Site” in this CC shall also be read as “Interface Site” where the context requires and until the OTSUA Transfer Time). Each User shall, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement, provide information to NGET to enable it to prepare the Site Responsibility Schedule.

Sub-division

CC.A.1.1.3 Each Site Responsibility Schedule will be subdivided to take account of any separate Connection Sites on that Complex.

Scope

CC.A.1.1.4 Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus:

(a) Plant/Apparatus ownership;
(b) Site Manager (Controller) (except in the case of Plant/Apparatus located in SPT’s Transmission Area);
(c) Safety issues comprising applicable Safety Rules and Control Person or other responsible person (Safety Co-ordinator), or such other person who is responsible for safety;
(d) Operations issues comprising applicable Operational Procedures and control engineer;
(e) Responsibility to undertake statutory inspections, fault investigation and maintenance.
Each **Connection Point** shall be precisely shown.

**Detail**

CC.A.1.1.5  
(a) In the case of **Site Responsibility Schedules** referred to in CC.A.1.1.1(b) and (c), with the exception of **Protection Apparatus** and **Intertrip Apparatus** operation, it will be sufficient to indicate the responsible **User** or **Transmission Licensee**, as the case may be.  

(b) In the case of the **Site Responsibility Schedule** referred to in CC.A.1.1.1(a) and for **Protection Apparatus** and **Intertrip Apparatus**, the responsible management unit must be shown in addition to the **User** or **Transmission Licensee**, as the case may be.

CC.A.1.1.6  
The **HV Apparatus Site Responsibility Schedule** for each **Connection Site** must include lines and cables emanating from or traversing\(^1\) the **Connection Site**.

**Issue Details**

CC.A.1.1.7  
Every page of each **Site Responsibility Schedule** shall bear the date of issue and the issue number.

**Accuracy Confirmation**

CC.A.1.1.8  
When a **Site Responsibility Schedule** is prepared it shall be sent by **NGET** to the **Users** involved for confirmation of its accuracy.

CC.A.1.1.9  
The **Site Responsibility Schedule** shall then be signed on behalf of **NGET** by its **Responsible Manager** (see CC.A.1.1.16) and on behalf of each **User** involved by its **Responsible Manager** (see CC.A.1.1.16), by way of written confirmation of its accuracy. For **Connection Sites** in Scotland or **Offshore**, the **Site Responsibility Schedule** will also be signed on behalf of the **Relevant Transmission Licensee** by its **Responsible Manager**.

**Distribution and Availability**

CC.A.1.1.10  
Once signed, two copies will be distributed by **NGET**, not less than two weeks prior to its implementation date, to each **User** which is a party on the **Site Responsibility Schedule**, accompanied by a note indicating the issue number and the date of implementation.

CC.A.1.1.11  
**NGET** and **Users** must make the **Site Responsibility Schedules** readily available to operational staff at the **Complex** and at the other relevant control points.

**Alterations to Existing Site Responsibility Schedules**

CC.A 1.1.12  
Without prejudice to the provisions of CC.A.1.1.15 which deals with urgent changes, when a **User** identified on a **Site Responsibility Schedule** becomes aware that an alteration is necessary, it must inform **NGET** immediately and in any event 8 weeks prior to any change taking effect (or as soon as possible after becoming aware of it, if less than 8 weeks remain when the **User** becomes aware of the change). This will cover the commissioning of new **Plant** and/or **Apparatus** at the **Connection Site**, whether requiring a revised **Bilateral Agreement** or not, de-commissioning of **Plant** and/or **Apparatus**, and other changes which affect the accuracy of the **Site Responsibility Schedule**.

CC.A 1.1.13  
Where **NGET** has been informed of a change by a **User**, or itself proposes a change, it will prepare a revised **Site Responsibility Schedule** by not less than six weeks prior to the change taking effect (subject to it having been informed or knowing of the change eight weeks prior to that time) and the procedure set out in CC.A.1.1.8 shall be followed with regard to the revised **Site Responsibility Schedule**.

CC.A 1.1.14  
The revised **Site Responsibility Schedule** shall then be signed in accordance with the procedure set out in CC.A.1.1.9 and distributed in accordance with the procedure set out in CC.A.1.1.10, accompanied by a note indicating where the alteration(s) has/have been made, the new issue number and the date of implementation.

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\(^1\) Details of circuits traversing the **Connection Site** are only needed from the date which is the earlier of the date when the **Site Responsibility Schedule** is first updated and 15\(^{th}\) October 2004. In **Scotland** or **Offshore**, from a date to be agreed between **NGET** and the **Relevant Transmission Licensee**.
Urgent Changes

CC.A.1.1.15 When a User identified on a Site Responsibility Schedule, or NGET, as the case may be, becomes aware that an alteration to the Site Responsibility Schedule is necessary urgently to reflect, for example, an emergency situation which has arisen outside its control, the User shall notify NGET, or NGET shall notify the User, as the case may be, immediately and will discuss:

(a) what change is necessary to the Site Responsibility Schedule;
(b) whether the Site Responsibility Schedule is to be modified temporarily or permanently;
(c) the distribution of the revised Site Responsibility Schedule.

NGET will prepare a revised Site Responsibility Schedule as soon as possible, and in any event within seven days of it being informed of or knowing the necessary alteration. The Site Responsibility Schedule will be confirmed by Users and signed on behalf of NGET and Users (by the persons referred to in CC.A.1.1.9) as soon as possible after it has been prepared and sent to Users for confirmation.

Responsible Managers

CC.A.1.1.16 Each User shall, prior to the Completion Date under each Bilateral Agreement and/or Construction Agreement, supply to NGET a list of Managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User and NGET shall, prior to the Completion Date under each Bilateral Agreement and/or Construction Agreement, supply to that User the name of its Responsible Manager and for Connection Sites in Scotland or Offshore, the name of the Relevant Transmission Licensee’s Responsible Manager and each shall supply to the other any changes to such list six weeks before the change takes effect where the change is anticipated, and as soon as possible after the change, where the change was not anticipated.

De-commissioning of Connection Sites

CC.A.1.1.17 Where a Connection Site is to be de-commissioned, whichever of NGET or the User who is initiating the de-commissioning must contact the other to arrange for the Site Responsibility Schedule to be amended at the relevant time.
PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

______________________________ AREA

COMPLEX: _______________________ SCHEDULE: ________________

CONNECTION SITE: ________________

<table>
<thead>
<tr>
<th>ITEM OF PLANT/APPARATUS</th>
<th>PLANT APPARATUS OWNER</th>
<th>SITE MANAGER</th>
<th>SAFETY RULES</th>
<th>CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY CO-ORDINATOR)</th>
<th>OPERATIONAL PROCEDURES</th>
<th>CONTROL OR OTHER RESPONSIBLE ENGINEER</th>
<th>PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION &amp; MAINTENANCE</th>
<th>REMARKS</th>
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# PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

___ AREA 

**COMPLEX:** ___________________________  **SCHEDULE:** _____________

**CONNECTION SITE:** ________________

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<tr>
<th>ITEM OF PLANT/APPARATUS</th>
<th>PLANT APPARATUS OWNER</th>
<th>SITE MANAGER</th>
<th>SAFETY OPERATIONS</th>
<th>SAFETY RULES</th>
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<th>PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION &amp; MAINTENANCE</th>
<th>REMARKS</th>
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**NOTES:**

SIGNED: ________________ NAME: __________________ COMPANY: ______________ DATE: _____________

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<th>Responsible Management Unit</th>
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APPENDIX 2 - OPERATION DIAGRAMS

PART 1A - PROCEDURES RELATING TO OPERATION DIAGRAMS
PART 1B - PROCEDURES RELATING TO GAS ZONE DIAGRAMS

- **Gas Insulated Busbar**
- **Double-Break Disconnecter**
- **External Mounted Current Transformer (where separate primary apparatus)**
- **Gas Boundary**
- **Stop Valve Normally Closed**
- **Gas/Cable Boundary**
- **Stop Valve Normally Open**
- **Gas/Air Boundary**
- **Gas Monitor**
- **Gas/Transformer Boundary**
- **Filter**
- **Maintenance Valve**
- **Quick Acting Coupling**
PART 2 - NON-EXHAUSTIVE LIST OF APPARATUS 
TO BE INCLUDED ON OPERATION DIAGRAMS

Basic Principles

(1) Where practicable, all the HV Apparatus on any Connection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the Connection Site.

(2) Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.

(3) The Operation Diagram must show accurately the current status of the Apparatus e.g. whether commissioned or decommissioned. Where decommissioned, the associated switchbay will be labelled “spare bay”.

(4) Provision will be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

(5) Operation Diagrams will be prepared in A4 format or such other format as may be agreed with NGET.

(6) The Operation Diagram should normally be drawn single line. However, where appropriate, detail which applies to individual phases shall be shown. For example, some HV Apparatus is numbered individually per phase.

Apparatus To Be Shown On Operation Diagram

(1) Busbars
(2) Circuit Breakers
(3) Disconnector (Isolator) and Switch Disconnecters (Switching Isolators)
(4) Disconnectors (Isolators) - Automatic Facilities
(5) Bypass Facilities
(6) Earthing Switches
(7) Maintenance Earths
(8) Overhead Line Entries
(9) Overhead Line Traps
(10) Cable and Cable Sealing Ends
(11) Generating Unit
(12) Generator Transformers
(13) Generating Unit Transformers, Station Transformers, including the lower voltage circuit-breakers.
(14) Synchronous Compensators
(15) Static Variable Compensators
(16) Capacitors (including Harmonic Filters)
(17) Series or Shunt Reactors (Referred to as “Inductors” at nuclear power station sites)
(18) Supergrid and Grid Transformers
(19) Tertiary Windings
(20) Earthing and Auxiliary Transformers
(21) Three Phase VT’s
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<td>Single Phase VT &amp; Phase Identity</td>
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<td>23</td>
<td>High Accuracy VT and Phase Identity</td>
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<td>Surge Arrestors/Diverters</td>
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<td>Neutral Earthing Arrangements on HV Plant</td>
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<td>26</td>
<td>Fault Throwing Devices</td>
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<td>Single Phase Transformers (BR) Neutral and Phase Connections</td>
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<td>Current Transformers (where separate plant items)</td>
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<td>Wall Bushings</td>
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<td>Combined VT/CT Units</td>
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<td>Shorting and Discharge Switches</td>
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<td>Thyristor</td>
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<td>35</td>
<td>Resistor with Inherent Non-Linear Variability, Voltage Dependent</td>
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<td>Gas Zone</td>
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APPENDIX 3 - 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 Onshore 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 Offshore Generating Unit in a Large Power Station,

(b) each DC Converter at a DC Converter Station which has a Completion Date on or after 1 April 2005 or each Offshore DC Converter which is part of a Large Power Station.

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

(d) each Onshore 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 50MW or more.

(e) each Offshore Power Park Module in a Large Power Station with a Registered Capacity of 50MW or more.

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,

(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 Power Stations with a Registered Capacity less than 50MW.

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

(viii) an OTSDUW DC Converter where the Interface Point Capacity is less than 50MW.

OTSDUW Plant and Apparatus should facilitate the delivery of frequency response services provided by Offshore Generating Units and Offshore Power Park Modules at the Interface Point.

The functional definition provides appropriate performance criteria relating to the provision of Frequency control by means of 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 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 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 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 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 Frequency response in excess of the identified minimum requirement.

The 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 Frequency response requirement for a Frequency deviation of 0.5 Hz. For example, if the Frequency deviation is 0.2 Hz, the corresponding minimum Frequency response requirement is 40% of the level shown in Figure CC.A.3.1. The 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 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).
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 NGET 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 Frequency change to the plant control system (i.e. governor and load controller). The injected signal is a linear ramp from zero to 0.5 Hz Frequency change over a ten second period, and is sustained at 0.5 Hz Frequency change thereafter, as illustrated diagrammatically in figures CC.A.3.2 and CC.A.3.3. In the case of an Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded DC Converter Station not subject to a Bilateral Agreement, NGET may require the Network Operator within whose System the Embedded Medium Power Station or Embedded DC Converter Station is situated, to ensure that the Embedded Person performs the dynamic response tests reasonably required by NGET in order to demonstrate compliance within the relevant requirements in the CC.

The Primary Response capability (P) of a Generating Unit or a CCGT Module or Power Park Module or 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. This increase in Active Power output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the Frequency fall as illustrated by the response from Figure CC.A.3.2.

The Secondary Response capability (S) of a Generating Unit or a CCGT Module or Power Park Module or 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 Power Park Module or 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. This reduction in Active Power output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the Frequency rise as illustrated by the response in Figure CC.A.3.2.

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 - FAULT RIDE THROUGH REQUIREMENTS

APPENDIX 4A - FAULT RIDE THROUGH REQUIREMENTS FOR ONSHORE SYNCHRONOUS GENERATING UNITS, ONSHORE POWER PARK MODULES, ONSHORE DC CONVERTERS OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT, OFFSHORE SYNCHRONOUS GENERATING UNITS IN A LARGE POWER STATION, OFFSHORE POWER PARK MODULES IN A LARGE POWER STATION AND OFFSHORE DC CONVERTERS IN A LARGE POWER STATION WHICH SELECT TO MEET THE FAULT RIDE THROUGH REQUIREMENTS AT THE INTERFACE POINT

CC.A.4A.1 Scope
The fault ride through requirement is defined in CC.6.3.15.1 (a), (b) and CC.6.3.15.3. This Appendix provides illustrations by way of examples only of CC.6.3.15.1 (a) (i) and further background and illustrations to CC.6.3.15.1 (1b) (i) and CC.6.3.15.1 (2b) (i) and is not intended to show all possible permutations.

CC.A.4A.2 Short Circuit Faults At Supergrid Voltage On The Onshore Transmission System Up To 140ms In Duration
For short circuit faults at Supergrid Voltage on the Onshore Transmission System (which could be at an Interface Point) up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15.1 (a) (i). Figures CC.A.4A.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.

![Diagram](image)

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

Figure CC.A.4A.1 (a)
CC.A.4A.3  **Supergrid Voltage Dips On The Onshore Transmission System Greater Than 140ms In Duration**

CC.A.4A.3.1 Requirements applicable to **Synchronous Generating Units** subject to **Supergrid Voltage** dips on the **Onshore Transmission System** greater than 140ms in duration.

For balanced **Supergrid Voltage** dips on the **Onshore Transmission System** having durations greater than 140ms and up to 3 minutes, the fault ride through requirement is defined in CC.6.3.15.1 (1b) and Figure 5a which is reproduced in this Appendix as Figure CC.A.4A.3.1 and termed 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 **Onshore Transmission System** (or **User System** if located **Onshore**) to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected **Synchronous Generating Units** must withstand or ride through.

Figures CC.A.4A.3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
Figure CC.A.4A3.1

Figure CC.A.4A3.2 (a)
CC.A.4A3.2 Requirements applicable to Power Park Modules or OTSDUW Plant and Apparatus subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

For balanced Supergrid Voltage dips on the Onshore Transmission System (which could be at an Interface Point) having durations greater than 140ms and up to 3 minutes the fault ride through requirement is defined in CC.6.3.15.1 (2b) and Figure 5b which is reproduced in this Appendix as Figure CC.A.4A3.3 and termed 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 Onshore Transmission System (or User System if located Onshore) to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected Power Park Modules or OTSDUW Plant and Apparatus must withstand or ride through.

Figures CC.A.4A.4 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
Figure CC.A.4A3.4 (b)

50% retained voltage, 710ms duration

Figure CC.A.4A3.4 (c)

85% retained voltage, 3 minutes duration
APPENDIX 4B - FAULT RIDE THROUGH REQUIREMENTS FOR OFFSHORE GENERATING UNITS IN A LARGE POWER STATION, OFFSHORE POWER PARK MODULES IN A LARGE POWER STATION AND OFFSHORE DC CONVERTERS IN A LARGE POWER STATION WHICH SELECT TO MEET THE FAULT RIDE THROUGH REQUIREMENTS AT THE LV SIDE OF THE OFFSHORE PLATFORM AS SpecIFIED IN CC.6.3.15.2

CC.A.4B.1 Scope

The fault ride through requirement is defined in CC.6.3.15.2 (a), (b) and CC.6.3.15.3. This Appendix provides illustrations by way of examples only of CC.6.3.15.2 (a) (i) and further background and illustrations to CC.6.3.15.2 (1b) and CC.6.3.15.2 (2b) and is not intended to show all possible permutations.

CC.A.4B.2 Voltage Dips On The LV Side Of The Offshore Platform Up To 140ms In Duration

For voltage dips on the LV Side of the Offshore Platform which last up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15.2 (a) (i). This includes Figure 6 which is reproduced here in Figure CC.A.4B.1. The purpose of this requirement is to translate the conditions caused by a balanced or unbalanced fault which occurs on the Onshore Transmission System (which may include the Interface Point) at the LV Side of the Offshore Platform.

\[ \frac{V}{V_N} \]

\[ 100\% \]

\[ 94\% \]

\[ 60\% \]

\[ 15\% \]

\[ 0 \quad 140\text{ms} \quad 300\text{ms} \quad \text{Time} \]

\[ V/V_N \text{ is the ratio of the voltage at the LV side of the Offshore Platform to the nominal voltage of the LV side of the Offshore Platform.} \]

Figure CC.A.4B.1

Figures CC.A.4B.2 (a) and CC.A.4B.2 (b) illustrate two typical examples of the voltage recovery seen at the LV Side of the Offshore Platform for a short circuit fault cleared within 140ms by (a) two circuit breakers and (b) three circuit breakers on the Onshore Transmission System.
CCA.4B.3 Voltage Dips Which Occur On The LV Side Of The Offshore Platform Greater Than 140ms In Duration

CC.A.4B.3.1 Requirements applicable to Offshore Synchronous Generating Units subject to voltage dips which occur on the LV Side of the Offshore Platform greater than 140ms in duration.

In addition to CC.A.4B.2 the fault ride through requirements applicable to Offshore Synchronous Generating Units during balanced voltage dips which occur at the LV Side of the Offshore Platform and having durations greater than 140ms and up to 3 minutes are defined in CC.6.3.15.2 (1b) and Figure 7a which is reproduced in this Appendix as Figure CC.A.4B3.1 and termed the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at the LV Side of the Offshore Platform to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected Offshore Synchronous Generating Units must withstand or ride through.
Figures CC.A.4B3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
CC.A.4B.3.2 Requirements applicable to Offshore Power Park Modules subject to Voltage Dips Which Occur On The LV Side Of The Offshore Platform Greater Than 140ms in Duration.

In addition to CCA.4B.2 the fault ride through requirements applicable for Offshore Power Park Modules during balanced voltage dips which occur at the LV Side of the Offshore Platform and have durations greater than 140ms and up to 3 minutes are defined in CC.6.3.15.2 (2b) (i) and Figure 7b which is reproduced in this Appendix as Figure CC.A.4B.4 and termed the voltage–duration profile.
This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at the **LV Side of the Offshore Platform** to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected **Offshore Power Park Modules** must withstand or ride through.

Figures CC.A.4B.5 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

![Graph showing voltage at LV Side of Offshore Platform](image)

**Figure CC.A.4B.4**

![Graph showing 30% retained voltage, 384ms duration](image)

**Figure CC.A.4B.5 (a)**
Figure CC.A.4B.5(b)

50% retained voltage, 710 ms duration

Figure CC.A.4B.5(c)

85% retained voltage, 3 minutes duration
CC.A.5.1  Low Frequency Relays

The Low Frequency Relays to be used shall have a setting range of 47.0 to 50Hz and be suitable for operation from a nominal AC input of 63.5, 110 or 240V. The following general parameters specify the requirements of approved Low Frequency Relays for automatic installations installed and commissioned after 1\textsuperscript{st} April 2007 and provide an indication, without prejudice to the provisions that may be included in a Bilateral Agreement, for those installed and commissioned before 1\textsuperscript{st} April 2007:

(a) Frequency settings: 47-50Hz in steps of 0.05Hz or better, preferably 0.01Hz;
(b) Operating time: Relay operating time shall not be more than 150 ms;
(c) Voltage lock-out: Selectable within a range of 55 to 90\% of nominal voltage;
(d) Facility stages: One or two stages of Frequency operation;
(e) Output contacts: Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations:
(f) Accuracy: 0.01 Hz maximum error under reference environmental and system voltage conditions. 0.05 Hz maximum error at 8\% of total harmonic distortion Electromagnetic Compatibility Level.

CC.A.5.2  Low Frequency Relay Voltage Supplies

CC.A.5.2.1 It is essential that the voltage supply to the Low Frequency Relays shall be derived from the primary System at the supply point concerned so that the Frequency of the Low Frequency Relays input voltage is the same as that of the primary System. This requires either:

(a) the use of a secure supply obtained from voltage transformers directly associated with the grid transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or
(b) the use of the substation 240V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the supply point concerned and is never derived from a standby supply Generating Unit or from another part of the User System.

CC.A.5.3  Scheme Requirements

CC.A.5.3.1 The tripping facility should be engineered in accordance with the following reliability considerations:

(a) Dependability

Failure to trip at any one particular Demand shedding point would not harm the overall operation of the scheme. However, many failures would have the effect of reducing the amount of Demand under low Frequency control. An overall reasonable minimum requirement for the dependability of the Demand shedding scheme is 96\%, i.e. the average probability of failure of each Demand shedding point should be less than 4\%. Thus the Demand under low Frequency control will not be reduced by more than 4\% due to relay failure.

(b) Outages

Low Frequency Demand shedding schemes will be engineered such that the amount of Demand under control is as specified in Table CC.A.5.5.1a and is not reduced unacceptably during equipment outage or maintenance conditions.
CC.A.5.3.2 The total operating time of the scheme, including circuit breakers operating time, shall where reasonably practicable, be less than 200 ms. For the avoidance of doubt, the replacement of plant installed prior to October 2009 will not be required in order to achieve lower total scheme operating times.

CC.A.5.4 Low Frequency Relay Testing
CC.A.5.4.1 Low Frequency Relays installed and commissioned after 1st January 2007 shall be type tested in accordance with and comply with the functional test requirements for Frequency Protection contained in Energy Networks Association Technical Specification 48-6-5 Issue 1 dated 2005 “ENA Protection Assessment Functional Test Requirements – Voltage and Frequency Protection”.

For the avoidance of doubt, Low Frequency Relays installed and commissioned before 1st January 2007 shall comply with the version of CC.A.5.1.1 applicable at the time such Low Frequency Relays were commissioned.

CC.A.5.5 Scheme Settings
CC.A.5.5.1 Table CC.A.5.5.1a shows, for each Transmission Area, the percentage of Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand that each Network Operator whose System is connected to the Onshore Transmission System within such Transmission Area shall disconnect by Low Frequency Relays at a range of frequencies. Where a Network Operator’s System is connected to the National Electricity Transmission System in more than one Transmission Area, the settings for the Transmission Area in which the majority of the Demand is connected shall apply.

<table>
<thead>
<tr>
<th>Frequency Hz</th>
<th>% Demand disconnection for each Network Operator in Transmission Area</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NGET</td>
</tr>
<tr>
<td>48.8</td>
<td>5</td>
</tr>
<tr>
<td>48.75</td>
<td>5</td>
</tr>
<tr>
<td>48.7</td>
<td>10</td>
</tr>
<tr>
<td>48.6</td>
<td>7.5</td>
</tr>
<tr>
<td>48.5</td>
<td>7.5</td>
</tr>
<tr>
<td>48.4</td>
<td>7.5</td>
</tr>
<tr>
<td>48.2</td>
<td>7.5</td>
</tr>
<tr>
<td>48.0</td>
<td>5</td>
</tr>
<tr>
<td>47.8</td>
<td>5</td>
</tr>
<tr>
<td>Total % Demand</td>
<td>60</td>
</tr>
</tbody>
</table>

Table CC.A.5.5.1a

Note – the percentages in table CC.A.5.5.1a are cumulative such that, for example, should the frequency fall to 48.6 Hz in the NGET Transmission Area, 27.5% of the total Demand connected to the National Electricity Transmission System in the NGET Transmission Area shall be disconnected by the action of Low Frequency Relays.

The percentage Demand at each stage shall be allocated as far as reasonably practicable. The cumulative total percentage Demand is a minimum.
APPEENDIX 6 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR ONSHORE SYNCHRONOUS GENERATING UNITS

CC.A.6.1 Scope

CC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for Onshore Synchronous Generating Units that must be complied with by the User. This Appendix does not limit any site specific requirements that may be included in a Bilateral Agreement where in NGET’s reasonable opinion these facilities are necessary for system reasons.

CC.A.6.1.2 Where the requirements may vary the likely range of variation is given in this Appendix. It may be necessary to specify values outside this range where NGET identifies a system need, and notwithstanding anything to the contrary NGET may specify in the Bilateral Agreement values outside of the ranges provided in this Appendix. The most common variations are in the on-load excitation ceiling voltage requirements and the response time required of the Exciter. Actual values will be included in the Bilateral Agreement.

CC.A.6.1.3 Should a Generator anticipate making a change to the excitation control system it shall notify NGET under the Planning Code (PC.A.1.2(b) and (c)) as soon as the Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

CC.A.6.2 Requirements

CC.A.6.2.1 The Excitation System of an Onshore Synchronous Generating Unit shall include an excitation source (Exciter), a Power System Stabiliser and a continuously acting Automatic Voltage Regulator (AVR) and shall meet the following functional specification.

CC.A.6.2.2 In respect of Onshore Synchronous Generating Units with a Completion Date on or after 1 January 2009, and Onshore Synchronous Generating Units with a Completion Date before 1 January 2009 subject to a Modification to the excitation control facilities where the Bilateral Agreement does not specify otherwise, the continuously acting automatic excitation control system shall include a Power System Stabiliser (PSS) as a means of supplementary control. The functional specification of the Power System Stabiliser is included in CC.A.6.2.5.

CC.A.6.2.3 Steady State Voltage Control

CC.A.6.2.3.1 An accurate steady state control of the Onshore Generating Unit pre-set terminal voltage is required. As a measure of the accuracy of the steady-state voltage control, the Automatic Voltage Regulator shall have static zero frequency gain, sufficient to limit the change in terminal voltage to a drop not exceeding 0.5% of rated terminal voltage, when the Onshore Generating Unit output is gradually changed from zero to rated MVA output at rated voltage, Active Power and Frequency.

CC.A.6.2.4 Transient Voltage Control

CC.A.6.2.4.1 For a step change from 90% to 100% of the nominal Onshore Generating Unit terminal voltage, with the Onshore Generating Unit on open circuit, the Excitation System response shall have a damped oscillatory characteristic. For this characteristic, the time for the Onshore Generating Unit terminal voltage to first reach 100% shall be less than 0.6 seconds. Also, the time to settle within 5% of the voltage change shall be less than 3 seconds.
CC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the **Onshore Generating Unit** is subjected to a large voltage disturbance, the **Exciter** whose output is varied by the **Automatic Voltage Regulator** shall be capable of providing its achievable upper and lower limit ceiling voltages to the **Onshore Generating Unit** field in a time not exceeding that specified in the **Bilateral Agreement**. This will normally be not less than 50 ms and not greater than 300 ms. The achievable upper and lower limit ceiling voltages may be dependent on the voltage disturbance.

CC.A.6.2.4.3 The **Exciter** shall be capable of attaining an **Excitation System On Load Positive Ceiling Voltage** of not less than a value specified in the **Bilateral Agreement** that will be:

- not less than 2 per unit (pu)
- normally not greater than 3 pu
- exceptionally up to 4 pu

of **Rated Field Voltage** when responding to a sudden drop in voltage of 10 percent or more at the **Onshore Generating Unit** terminals. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

CC.A.6.2.4.4 If a static type **Exciter** is employed:

(i) the field voltage should be capable of attaining a negative ceiling level specified in the **Bilateral Agreement** after the removal of the step disturbance of CC.A.6.2.4.3. The specified value will be 80% of the value specified in CC.A.6.2.4.3. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

(ii) the **Exciter** must be capable of maintaining free firing when the **Onshore Generating Unit** terminal voltage is depressed to a level which may be between 20% to 30% of rated terminal voltage

(iii) the **Exciter** shall be capable of attaining a positive ceiling voltage not less than 80% of the **Excitation System On Load Positive Ceiling Voltage** upon recovery of the **Onshore Generating Unit** terminal voltage to 80% of rated terminal voltage following fault clearance. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

(iv) The requirement to provide a separate power source for the **Exciter** will be specified in the **Bilateral Agreement** if **NGET** identifies a **Transmission System** need.

CC.A.6.2.5 **Power Oscillations Damping Control**

CC.A.6.2.5.1 To allow the **Onshore Generating Unit** to maintain second and subsequent swing stability and also to ensure an adequate level of low frequency electrical damping power, the **Automatic Voltage Regulator** shall include a **Power System Stabiliser** as a means of supplementary control.

CC.A.6.2.5.2 Whatever supplementary control signal is employed, it shall be of the type which operates into the **Automatic Voltage Regulator** to cause the field voltage to act in a manner which results in the damping power being improved while maintaining adequate synchronising power.

CC.A.6.2.5.3 The arrangements for the supplementary control signal shall ensure that the **Power System Stabiliser** output signal relates only to changes in the supplementary control signal and not the steady state level of the signal. For example, if generator electrical power output is chosen as a supplementary control signal then the **Power System Stabiliser** output should relate only to changes in generator electrical power output and not the steady state level of power output. Additionally the **Power System Stabiliser** should not react to mechanical power changes in isolation for example during rapid changes in steady state load or when providing frequency response.

CC.A.6.2.5.4 The output signal from the **Power System Stabiliser** shall be limited to not more than ±10% of the **Onshore Generating Unit** terminal voltage signal at the **Automatic Voltage Regulator** input. The gain of the **Power System Stabiliser** shall be such that an increase in the gain by a factor of 3 shall not cause instability.
CC.A.6.2.5.5 The **Power System Stabiliser** shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application.

CC.A.6.2.5.6 The **Generator** will agree **Power System Stabiliser** settings with **NGET** prior to the on-load commissioning detailed in BC2.11.2(d). To allow assessment of the performance before on-load commissioning the **Generator** will provide to **NGET** a report covering the areas specified in CP.A.3.2.1.

CC.A.6.2.5.7 The **Power System Stabiliser** must be active within the **Excitation System** at all times when **Synchronised** including when the **Under Excitation Limiter** or **Over Excitation Limiter** are active. When operating at low load when **Synchronising** or **De-Synchronising** an **Onshore Generating Unit**, the **Power System Stabiliser** may be out of service.

CC.A.6.2.5.8 Where a **Power System Stabiliser** is fitted to a **Pumped Storage Unit** it must function when the **Pumped Storage Unit** is in both generating and pumping modes.

CC.A.6.2.6 Overall **Excitation System** Control Characteristics

CC.A.6.2.6.1 The overall **Excitation System** shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5 Hz will be judged to be acceptable for this application.

CC.A.6.2.6.2 The response of the **Automatic Voltage Regulator** combined with the **Power System Stabiliser** shall be demonstrated by injecting similar step signal disturbances into the **Automatic Voltage Regulator** reference as detailed in OC5A.2.2 and OC5.A.2.4. The **Automatic Voltage Regulator** shall include a facility to allow step injections into the **Automatic Voltage Regulator** voltage reference, with the **Onshore Generating Unit** operating at points specified by **NGET** (up to rated MVA output). The damping shall be judged to be adequate if the corresponding **Active Power** response to the disturbances decays within two cycles of oscillation.

CC.A.6.2.6.3 A facility to inject a band limited random noise signal into the **Automatic Voltage Regulator** voltage reference shall be provided for demonstrating the frequency domain response of the **Power System Stabiliser**. The tuning of the **Power System Stabiliser** shall be judged to be adequate if the corresponding **Active Power** response shows improved damping with the **Power System Stabiliser** in combination with the **Automatic Voltage Regulator** compared with the **Automatic Voltage Regulator** alone over the frequency range 0.3Hz – 2Hz.

CC.A.6.2.7 **Under-Excitation Limiters**

CC.A.6.2.7.1 The security of the power system shall also be safeguarded by means of MVAR **Under Excitation Limiters** fitted to the generator **Excitation System**. The **Under Excitation Limiter** shall prevent the **Automatic Voltage Regulator** reducing the generator excitation to a level which would endanger synchronous stability. The **Under Excitation Limiter** shall operate when the excitation system is providing automatic control. The **Under Excitation Limiter** shall respond to changes in the **Active Power** (MW) and the **Reactive Power** (MVAR), and to the square of the generator voltage in such a direction that an increase in voltage will permit an increase in leading MVAR. The characteristic of the **Under Excitation Limiter** shall be substantially linear from no-load to the maximum **Active Power** output of the **Onshore Generating Unit** at any setting and shall be readily adjustable.
CC.A.6.2.7.2 The performance of the Under Excitation Limiter shall be independent of the rate of change of the Onshore Generating Unit load and shall be demonstrated by testing as detailed in OC5.A.2.5. The resulting maximum overshoot in response to a step injection which operates the Under Excitation Limiter shall not exceed 4% of the Onshore Generating Unit rated MVA. The operating point of the Onshore Generating Unit shall be returned to a steady state value at the limit line and the final settling time shall not be greater than 5 seconds. When the step change in Automatic Voltage Regulator reference voltage is reversed, the field voltage should begin to respond without any delay and should not be held down by the Under Excitation Limiter. Operation into or out of the preset limit levels shall ensure that any resultant oscillations are damped so that the disturbance is within 0.5% of the Onshore Generating Unit MVA rating within a period of 5 seconds.

CC.A.6.2.7.3 The Generator shall also make provision to prevent the reduction of the Onshore Generating Unit excitation to a level which would endanger synchronous stability when the Excitation System is under manual control.

CC.A.6.2.8 Over-Excitation Limiters

CC.A.6.2.8.1 The settings of the Over-Excitation Limiter, where it exists, shall ensure that the generator excitation is not limited to less than the maximum value that can be achieved whilst ensuring the Onshore Generating Unit is operating within its design limits. If the generator excitation is reduced following a period of operation at a high level, the rate of reduction shall not exceed that required to remain within any time dependent operating characteristics of the Onshore Generating Unit.

CC.A.6.2.8.2 The performance of the Over-Excitation Limiter, where it exists, shall be demonstrated by testing as described in OC5.A.2.6. Any operation beyond the Over-Excitation Limit shall be controlled by the Over-Excitation Limiter without the operation of any Protection that could trip the Onshore Generating Unit.

CC.A.6.2.8.3 The Generator shall also make provision to prevent any over-excitation restriction of the generator when the Excitation System is under manual control, other than that necessary to ensure the Onshore Generating Unit is operating within its design limits.
APPENDIX 7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR ONSHORE NON-SYNCHRONOUS GENERATING UNITS, ONSHORE DC CONVERTERS, ONSHORE POWER PARK MODULES AND OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT

CC.A.7.1 Scope

CC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for Onshore Non-Synchronous Generating Units, Onshore DC Converters, Onshore Power Park Modules and OTSDUW Plant and Apparatus at the Interface Point that must be complied with by the User. This Appendix does not limit any site specific requirements that may be included in a Bilateral Agreement where in NGET's reasonable opinion these facilities are necessary for system reasons.

CC.A.7.1.2 Proposals by Generators to make a change to the voltage control systems are required to be notified to NGET under the Planning Code (PC.A.1.2(b) and (c)) as soon as the Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

CC.A.7.2 Requirements

CC.A.7.2.1 NGET requires that the continuously acting automatic voltage control system for the Onshore Non-Synchronous Generating Unit, Onshore DC Converter or Onshore Power Park Module or OTSDUW Plant and Apparatus shall meet the following functional performance specification. If a Network Operator has confirmed to NGET that its network to which an Embedded Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus is connected is restricted such that the full reactive range under the steady state voltage control requirements (CC.A.7.2.2) cannot be utilised, NGET may specify in the Bilateral Agreement alternative limits to the steady state voltage control range that reflect these restrictions. Where the Network Operator subsequently notifies NGET that such restriction has been removed, NGET may propose a Modification to the Bilateral Agreement (in accordance with the CUSC contract) to remove the alternative limits such that the continuously acting automatic voltage control system meets the following functional performance specification. All other requirements of the voltage control system will remain as in this Appendix.

CC.A.7.2.2 Steady State Voltage Control

CC.A.7.2.2.1 The Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus shall provide continuous steady state control of the voltage at the Onshore Grid Entry Point (or Onshore User System Entry Point if Embedded) (or the Interface Point in the case of OTSDUW Plant and Apparatus) with a Setpoint Voltage and Slope characteristic as illustrated in Figure CC.A.7.2.2a. It should be noted that where the Reactive Power capability requirement of a directly connected Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module in Scotland, or OTSDUW Plant and Apparatus in Scotland as specified in CC.6.3.2 (c), is not at the Onshore Grid Entry Point or Interface Point, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer.
CC.A.7.2.2.2 The continuously acting automatic control system shall be capable of operating to a **Setpoint Voltage** between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt values of 95%, 95.25%, 95.5% … may be specified, but not intermediate values. The initial **Setpoint Voltage** will be 100%. The tolerance within which this **Setpoint Voltage** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. NGET may request the **Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%. For **Embedded Generators** the **Setpoint Voltage** will be discussed between NGET and the relevant **Network Operator** and will be specified to ensure consistency with CC.6.3.4.

CC.A.7.2.2.3 The **Slope** characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial **Slope** setting will be 4%. The tolerance within which this **Slope** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a **Slope** setting of 4%, the achieved value shall be between 3.5% and 4.5%. NGET may request the **Generator** to implement an alternative slope setting within the range of 2% to 7%. For **Embedded Generators** the **Slope** setting will be discussed between NGET and the relevant **Network Operator** and will be specified to ensure consistency with CC.6.3.4.
Grid Entry Point voltage
(or User System Entry Point voltage if Embedded)
(or Interface Point in the case of an OTSDW)

Figure CC.A.7.2.2b

Onshore Grid Entry Point voltage
(or Onshore User System Entry Point voltage if Embedded)
Connections at 33kV and below

Figure CC.A.7.2.2c
CC.A.7.2.2.4 Figure CC.A.7.2.2b shows the required envelope of operation for Onshore Non-Synchronous Generating Units, Onshore DC Converters, OTSDUW Plant and Apparatus and Onshore Power Park Modules except for those Embedded at 33kV and below or directly connected to the National Electricity Transmission System at 33kV and below. Figure CC.A.7.2.2c shows the required envelope of operation for Onshore Non-Synchronous Generating Units, Onshore DC Converters and Onshore Power Park Modules Embedded at 33kV and below or directly connected to the National Electricity Transmission System at 33kV and below. Where the Reactive Power capability requirement of a directly connected Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module in Scotland, as specified in CC.6.3.2 (c), is not at the Onshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer. The enclosed area within points ABCDEFGH is the required capability range within which the Slope and Setpoint Voltage can be changed.

CC.A.7.2.2.5 Should the operating point of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module deviate so that it is no longer a point on the operating characteristic (figure CC.A.7.2.2a) defined by the target Setpoint Voltage and Slope, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

CC.A.7.2.2.6 Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum lagging limit at a Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) above 95%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum lagging Reactive Power output for voltage reductions down to 95%. This requirement is indicated by the line EF in figures CC.A.7.2.2b and CC.A.7.2.2c. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum leading limit at a Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) below 105%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum leading Reactive Power output for voltage increases up to 105%. This requirement is indicated by the line AB in figures CC.A.7.2.2b and CC.A.7.2.2c.
CC.A.7.2.2.7 For Onshore Grid Entry Point voltages (or Onshore User System Entry Point voltages if Embedded or Interface Point voltages) below 95%, the lagging Reactive Power capability of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures CC.A.7.2.2b and CC.A.7.2.2c. For Onshore Grid Entry Point voltages (or User System Entry Point voltages if Embedded or Interface Point voltages) above 105%, the leading Reactive Power capability of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures CC.A.7.2.2b and CC.A.7.2.2c. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum lagging limit at an Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) below 95%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter or Onshore Power Park Module shall maintain maximum lagging reactive current output for further voltage decreases. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum leading limit at a Onshore Grid Entry Point voltage (or User System Entry Point voltage if Embedded or Interface Point in the case of an OTSDUW Plant and Apparatus) above 105%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum leading reactive current output for further voltage increases.

CC.A.7.2.2.8 All OTSDUW Plant and Apparatus must be capable of enabling Users undertaking OTSDUW to comply with an instruction received from NGET relating to a variation of the Setpoint Voltage at the Interface Point within 2 minutes of such instruction being received.

CC.A.7.2.2.9 For OTSDUW Plant and Apparatus connected to a Network Operator’s System where the Network Operator has confirmed to NGET that its System is restricted in accordance with CC.A.7.2.1, clause CC.A.7.2.2.8 will not apply unless NGET can reasonably demonstrate that the magnitude of the available change in Reactive Power has a significant effect on voltage levels on the Onshore National Electricity Transmission System.

CC.A.7.2.3 Transient Voltage Control

CC.A.7.2.3.1 For an on-load step change in Onshore Grid Entry Point or Onshore User System Entry Point voltage, or in the case of OTSDUW Plant and Apparatus an on-load step change in Transmission Interface Point voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the Reactive Power output response of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAR seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure CC.A.7.2.3.1a.

(ii) the response shall be such that 90% of the change in the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module, will be achieved within

- 1 second, where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value, as required by CC.6.3.2 (or, if appropriate, CC.A.7.2.2.6 or CC.A.7.2.2.7); and
–  2 seconds, for **Plant and Apparatus** installed on or after 1 December 2017, where the step is sufficiently large to require a change in the steady state **Reactive Power** output from its maximum leading value to its maximum lagging value or vice versa.

(iii) the magnitude of the **Reactive Power** output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within 2 seconds from achieving 90% of the response as defined in CC.A.7.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state **Reactive Power**.

(v) following the transient response, the conditions of CC.A.7.2.2 apply.

![Graph showing the required response at 1 second.](image)

**Figure CC.A.7.2.3.1a**

**CC.A.7.2.3.2** An **Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus** or **Onshore Power Park Module** installed on or after 1 December 2017 shall be capable of

(a) changing its **Reactive Power** output from its maximum lagging value to its maximum leading value, or vice versa, then reverting back to the initial level of **Reactive Power** output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing its **Reactive Power** output from zero to its maximum leading value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to **NGET** in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to CC.A.7.2.3.1 where the change in **Reactive Power** output is in response to an on-load step change in **Onshore Grid Entry Point** or **Onshore User System Entry Point** voltage, or in the case of **OTSDUW Plant and Apparatus** an on-load step change in **Transmission Interface Point** voltage.

**CC.A.7.2.4** **Power Oscillation Damping**
CC.A.7.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a Power System Stabiliser (PSS) shall be specified in the Bilateral Agreement if, in NGET’s view, this is required for system reasons. However if a Power System Stabiliser is included in the voltage control system its settings and performance shall be agreed with NGET and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the Generator will provide to NGET a report covering the areas specified in CP.A.3.2.2.

CC.A.7.2.5 Overall Voltage Control System Characteristics

CC.A.7.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point voltage in the case of OTSDUW Plant and Apparatus).

CC.A.7.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should also meet this requirement.

CC.A.7.2.5.3 The response of the voltage control system (including the Power System Stabiliser if employed) shall be demonstrated by testing in accordance with OC5A.A.3.

< END OF CONNECTION CONDITIONS >