Stage 01: Modification Proposal

Grid Code

What stage is this document at?

01	Modification Proposal
02	Workgroup Report
03	Code Admin Consultation
04	Draft Final Modification Report
05	Report to the Authority

GC0118:

Mod Title: Modification to the Grid Code to accommodate the recent Distribution Code modification to Engineering Recommendation P28 –*Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom.*

Purpose of Modification: The purpose of this modification is to ensure the Grid Code implements the proposed changes as set out in the revised Engineering Recommendation P28 Issue 2 (2018) (subsequently referred to as EREC P28 Issue 2).

The Proposer recommends that this modification should be:

- Subject to the normal governance procedures.

This modification was raised **10 July 2018** and will be presented by the Proposer to the Panel on **18 July 2018.** The Panel will consider the Proposer's recommendation and determine the appropriate route.

High Impact: None

Medium Impact: 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. New developers of transmission connected generation installations, and existing users that make changes to existing installations with significant number of transformers that cause rapid voltage changes (RVCs) when energised, who are required to design their installations in accordance with the requirements and planning levels for RVCs in EREC P28 Issue 2.

Low Impact: Any User connected to or seeking connection with the National Electricity Transmission System, The modifications are intended not to unduly impact on or cause interference to existing Users of public electricity systems/networks.
Users that propose to connect disturbing equipment/fluctuating installations to the system, which could result in flicker, who need to carry out assessments and measurements in accordance with EREC P28 Issue 2.

Contents

Any Questions?

Contact:

Chrissie Brown

Code Administrator

christine.brown1@nationalgrid.com

019266563328

Proposer:

David Spillett

On behalf of the Distribution Network Licensees

Timetable

A timetable will be approved by the Grid Code Panel once the governance route is decided at the Panel meeting on **18 July 2018.**

Workgroup Meeting 1	dd month year
Workgroup Report presented to Panel	dd month year
Code Administration Consultation Report issued to the Industry	dd month year
Draft Final Modification Report presented to Panel	dd month year
Modification Panel decision	dd month year
Final Modification Report issued the Authority	dd month year
Decision implemented in Grid Code	dd month year

1.Summary

Defect

Engineering Recommendation (EREC) P28 Issue 1 was first published in 1989 to provide recommended planning limits for voltage fluctuations for connection of equipment to public electricity supply systems in the UK. EREC P28 Issue 1 was primarily concerned with assessment of voltage fluctuations and associated flicker produced by traditional domestic, commercial and industrial loads.

Since EREC P28 Issue 1 was first published, the factors affecting development of transmission systems and distribution networks, and equipment connected to them have changed significantly. There has been a shift towards connection of distributed/embedded generation equipment powered by renewable energies and other low carbon technology equipment. These types of modern equipment are capable of causing voltage fluctuations.

Significant developments in Electromagnetic Compatibility (EMC) requirements have also taken place, which are captured in the International Electro-technical Commission (IEC) 61000 series of Standards and technical reports. United Kingdom implementation of these Standards is captured in the various parts of BS EN 61000.

Engineering Recommendation P28 is referenced in the Grid Code and Distribution Code. A joint Grid Code and Distribution Code Working Group was established to oversee the revision of Engineering Recommendation P28 Issue 1 and associated modification to requirements for voltage fluctuation in the Distribution Code and the Grid Code and the working group has produced a revised version of Engineering Recommendation P28 i.e. EREC P28 Issue 2 which was submitted to the Authority for approval on 17 May 2018. Unfortunately as Engineering Recommendation P28 is referenced in the Grid Code as simply Engineering Recommendation P28 (no issue number) the Authority was unable to approve the modification without the EREC P28 Issue 2 changes reflected in the Grid Code hence why this Grid Code modification is being proposed.

What

There are a ten specific references relating to Engineering Recommendation P28 in the Grid Code that need to be considered and revised and they are as follows:

- GLOSSARY AND DEFINITIONS
    - Flicker Severity
- PLANNING CODE
    - PC.A.4.7 General Demand Data - PC.A.4.7.1 (f)
    - Appendix C Technical Design Criteria Part 1 PC.C.3 SHETLs Technical Design Criteria (Item4)
    - Appendix E – Offshore Transmission System and OTSDUW Plant and Apparatus Technical Design Criteria – PC.E.2 (Table)
- CONNECTION CONDITIONS
    - CC.6 Technical, Design and Operational Criteria Voltage Fluctuations CC6.1.7
- EUROPEAN CONNECTION CONDITIONS

    - ECC.6 Technical, Design and Operational Criteria
    - Voltage Fluctuations ECC.6.1.7
- OPERATING CODES
    - OC5.5.4 Test And Monitoring Assessment (Test Criteria)

- DATA REGISTRATION CODE
    - Schedule 7 - Load Characteristics at Grid Supply Points

All of the proposed changes bar revision to CC 6.1.7 and ECC 6.1.7 are editorial and relate to modifying the Grid Code so that the Code references EREC P28 Issue 2. Modification to CC 6.1.7 and ECC 6.1.7 is simply deleting duplicate text from the Grid Code that is already included in the new EREC P28 Issue 2.

Why

The changes are required to align the Grid Code and the Distribution Code with the new requirements of EREC P28 Issue 2. In addition it is recommended that text and diagrams in EREC P28 Issue 2 should not be duplicated in the Grid Code and that the Grid Code should only signpost the reader to EREC P28 Issue 2.

How

The solution (draft legal text) proposed is documented in Appendices A and B.

2.Governance

Justification for normal governance procedures

In its decision letter Ofgem (see appendix C) considered that there was not sufficient industry consideration of the impact of DCRP/PC/18/01/FMR (see appendix D) on other industry codes. Specifically, they did not consider that the impact on the Grid Code had been properly considered. Ofgem noted that Engineering Recommendation P28 is referenced multiple times within the Grid Code. The changes proposed under DCRP/PC/18/01/FMR, which have a direct impact on the requirements for parties connecting to the electricity networks, could result in consequential changes to Grid Code requirements that have not been assessed and which may be relevant to inform their decision.

Ofgem therefore expect distribution licensees and the Grid Code Review Panel (‘GCRP’) to work together and submit any proposed Distribution and Grid Code changes as a package, which should include co-ordinated implementation timetables. Ofgem expects the GCRP to discuss the issues set out in their decision letter and DCRP/MP/18/01 at the next GCRP meeting.

It is therefore recommended that the requirements of CC.6.1.7 and ECC 6.1.7 of the Grid Code are aligned with those in EREC P28 Issue 2 and the references in the Grid Code to Engineering Recommendation P28 is replaced with reference to Engineering Recommendation P28/2 Issue 2 (see appendix E).

A Distribution Code public Consultation which included Grid Code stakeholders was held from the 8th January 2018 to 31st January 2018. Full details of the response are contained in the aforementioned Report to Authority DCRP/PC/18/01/FMR.

Requested Next Steps

This modification should:

- be subject to normal governance procedures.

It is expected that the workgroup should hold no more than one meeting to consider and agree to the recommendations contained in this modification proposal.

The workgroup should then prepare a short report to the Panel. With Panel agreement a final Report to Authority should be submitted in conjunction with the DRCP Report recommending that the modification proposal should be approved.

3.Why Change?

The need for the change and the modification proposal is to align the Grid Code with the new Engineering Recommendation P28. Those changes are set out in section 1 of this report.

If the change is not addressed in the Grid Code then the Authority will not be able to approve the modification to Engineering Recommendation P28 Issue 2. Please note the recent Authority decision letter on DCRP/PC/18/01/RtA (see appendix C).

The following parties will be impacted with regards to complying with the new Engineering Recommendation P28 Issue 2:

- 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;
- New developers of transmission connected generation installations, and existing users that make changes to existing installations with significant number of transformers;
- Any User connected to or seeking connection with the National Electricity Transmission System:
- Users that propose to connect disturbing equipment/fluctuating installations to the system, which could result in flicker.

For additional background and context please also refer to the Distribution Code Final Modification Report DCRP/PC/18/01/FMR (see appendix C) which sets out the recommendation that modifications should be made to the Distribution Code and Engineering Recommendation P28, in relation to voltage fluctuations resulting from the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom.

ER P28 Issue 2 now:
a) Introduces requirements and planning levels for Rapid Voltage Changes (RVCs).
b) Improves definition and clarity of ‘worst case operating conditions’ to be used in the assessment of voltage fluctuations.
c) Includes an intermediate planning level and associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV to

improve co-ordination of flicker severity from higher to lower voltage supply systems.
d) Improves the definition of voltage step change.
e) Clarifies information requirements for assessment and responsibilities for provision of information.
f) Includes the application of transfer coefficients for determining voltage fluctuation contributions from different nodes.
g) Assesses voltage fluctuations caused by renewable energy and low carbon technologies.

4.Code Specific Matters

Technical Skillsets

A skill set and understanding in Power Quality standards and the actual application of Engineering Recommendation P28 would be helpful.

Reference Documents

- Grid Code
- Distribution Code
- Security and Quality of Supply Standard
- Engineering Recommendation P28 Issue 2 (2018)

5.Solution

Please refer to appendices A and B

6.Impacts and Other Considerations

The Distribution Code and the Grid Code are both impacted by the proposed modification to Engineering Recommendation P28 Issue 2 but this is mainly editorial, where the Codes signpost users to Engineering Recommendation P28 Issue 2.

The most significant impact is to the requirements for voltage fluctuation in CC.6.1.7 of the Grid Code, in particular Table CC.6.1.7. The limits for RVCs proposed in EREC P28 Issue 2 take into account those in the GC0076 modification to the Grid Code. The key differences between the requirements in EREC P28 Issue 2 and those in the Grid Code are as follows noting that the intention is to align the requirements in the Grid Code with those in EREC P28 Issue 2, so as to provide greater flexibility for customer connections and to be less onerous for customers to comply with.

- Allowable voltage changes are expressed as a percentage of nominal voltage (V_n) in P28 Issue 2 as opposed to a percentage of the initial voltage (V_o) in the Grid Code. The intention being to align with the approach taken in National and International Standards.
- For increases in voltage:

- EREC P28 Issue 2 proposes a limit on the maximum voltage change between two steady state conditions of $\Delta V_{max} \leq 6\%$ for a maximum duration of 0.8 s from the initiation of a voltage change.
    - The Grid Code has a limit of $\Delta V_{max} \leq 5\%$ for a maximum duration of 0.5 s.
- For decreases in voltage:
    - EREC P28 Issue 2 proposes a time limit of 100 ms from initiation of a voltage change during which the maximum voltage change permitted
      (-12% for 'very infrequent events' and -10% for 'infrequent events') can persist.
    - The Grid Code has a time limit of 80 ms from initiation of a voltage change during which the maximum permitted voltage change is -12%.
- For increases and decreases in voltage, EREC P28 Issue 2 permits a greater maximum number of occurrences for Category 3 'very infrequent' events:
    - EREC P28 Issue 2 proposes to permit up to a maximum of 4 RVCs in one day (irrespective of type of operational event causing the RVC) not more frequent than once every 3 months.
    - The Grid Code permits up to a maximum of 4 RVCs in one day (for commissioning, maintenance and fault restoration) typically not planned more than once per year on average over the lifetime of the connection.
- EREC P28 Issue 2 introduces an intermediate category of RVC (Category 2) for 'infrequent events', where up to a maximum of 4 RVCs in one day are permitted not more frequent than 4 times per month providing the $\Delta V_{max} \leq -10\%$ for ≤ 100 ms then reducing to ≤ 6% for up to 2 s after initiation of the event.

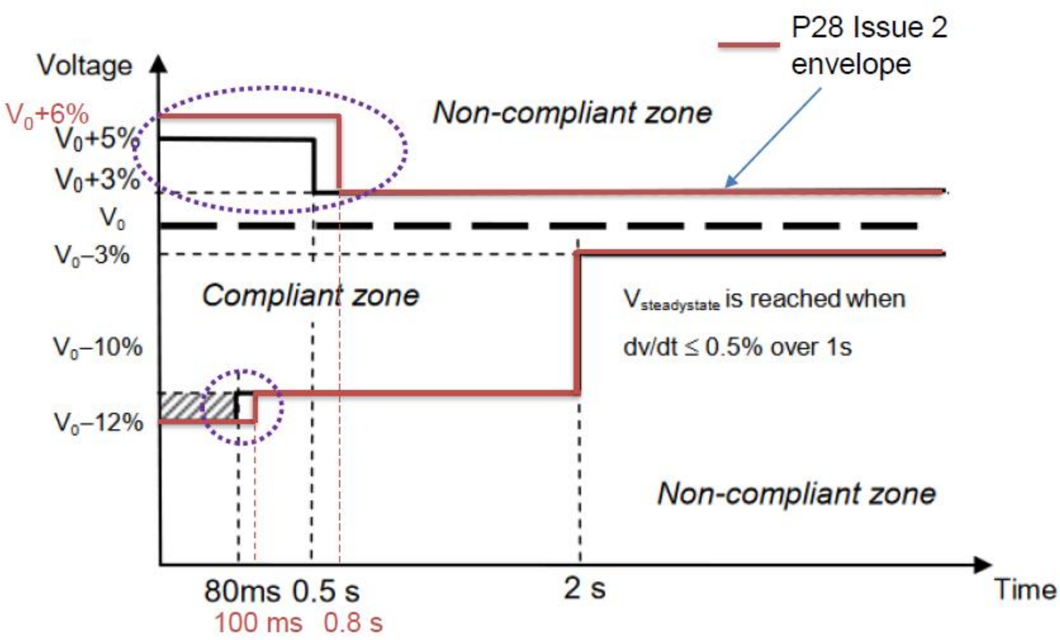

Figure CC.6.1.7 -
Time and magnitude limits for a category 3 Rapid Voltage Change

The difference between the voltage envelope for Rapid Voltage Changes in Figure CC.6.1.7 of the Grid Code and Table 4 of EREC P28/2 Issue 2 for Very Infrequent

RVCs are shown in the above figure. The P28 Working Group has proposed limits for RVC in EREC P28 Issue 2 that:

- generally align with those in Figure CC.6.1.7 for reductions in voltage.
- are absolute and compatible with EREC G59 and grid connected protection as well as TGN 288 for overvoltage.
- are compatible with immunity levels for customer equipment.
- should not result in unacceptable disturbance provided:-
    - events are sufficiently spaced apart.
    - multiple RVCs are completed within a small time window.
    - there is no damage to or tripping of customer equipment.

The impacts of the proposals for RVC limits in EREC P28 Issue 2 can be summarised as follows:

- There could be potentially a greater number of RVCs at any given PCC over a calendar year. The P28 WG believe the potentially greater number of RVCs permitted at a given PCC will not cause unacceptable disturbance to other customers.
- The changes to the RVC limits permit a grater number of transformer to be energised at the same time providing greater flexibility for design of user connections and for operation of the transmission system.
- The proposals will simplify restoring distributed generation following G59 events.
- There is no material impact on ΔV_{max} for decreases in voltage.

The proposed RVC limits in EREC P28 Issue 2 (and associated differences with the requirements in the Grid Code) reflect the:

- further work carried out by the Working Group and the experience of NGET in applying RVC limits since the GC0076 modification was implemented in the Grid Code. NGET's representative on the P28 Working Group oversaw the GC0076 modification the Grid Code and chaired the P28 RVC sub-group.
- limits for RVCs in Category 2 and Category 3 of Table 4 taking into account differences in the perceptibility of RVC compared with flicker associated with continuously fluctuating loads.

Please also note that the Security and Quality of Supply Standard (SQSS) Figure 6.1 references ER P28 (Issue 1) Figure 4. Figure 4 in ER P28 Issue 1 has been replaced by a slightly different Figure B.1.2 in EREC P28 Issue 2. Therefore the GCRP will need to consider a modification to the SQSS also. This will be subject to a separate modification proposal submitted to the SQSS Panel.

There are no practices affected and no systems impacted.

This modification does not impact on any Significant Code Review (SCR) or any other significant industry change project.

There are no consumer impacts as a result of this modification proposal.

7.Relevant Objectives

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

8.Implementation

This modification proposal should be implemented no later than 5 October 2018 or as soon as reasonably practicable to avoid any further delay of the approval of the Distribution Code modification currently awaiting approval of the Authority. There should be no costs attributed to any stakeholder in delivering and implementing this modification.

9.Legal Text

Legal text is included with this modification proposal. Please refer to appendices A and B

10.Recommendations

Panel is asked to:

Agree that this modification proposal should be subject to normal governance procedures and

Agree the Terms of Reference for the Grid Code Workgroup

Appendices

Appendix A - Glossary and Definitions – Draft legal text
Appendix B1- CONNECTION CONDITIONS I5R22 CC.6.1.7 - draft legal text
Appendix B2- EUROPEAN CONNECTION CONDITIONS I5R22 ECC.6.1.7- draft legal text
Appendix C - DCRP/18/01/FMR Decision Letter
Appendix D - DCRP_FMR_EREC P28 Issue 2_v0.4.1_Issued

Appendix A – Proposed Legal Text – Editorial Changes

New proposed legal text is highlighted in red.

- GLOSSARY AND DEFINITIONS
    - Flicker Severity
      *A value derived from 12 successive measurements of **Flicker Severity (Short Term)** (over a two hour period) and a calculation of the cube root of the mean sum of the cubes of 12 individual measurements, as further set out in **Engineering Recommendation** P28 Issue 2 as current at the Transfer Date*

- PLANNING CODE
    - PC.A.4.7 General Demand Data - PC.A.4.7.1 (f)
      *details of all loads which may cause **Demand** fluctuations greater than those permitted under **Engineering Recommendation** P28 Issue 2, Stage 1 at a **Point of Common Coupling** including the **Flicker Severity (Short Term)** and the **Flicker Severity (Long Term)**.*

    - Appendix C Technical Design Criteria - Part 1 SHETLs
      Technical Design Criteria (Item4)
      New Title for ER P28 Issue 2 - Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom
      In the table column entitled "Reference No" ER P28 should be modified to state P28 Issue 2

    - Appendix C Technical Design Criteria Part 2 - SPT's Technical and Design Criteria
      New Title for ER P28/2 - Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom
      In the table column entitled "Reference No" Engineering Recommendation ER P28 should be modified to state Engineering Recommendation P28 Issue 2

    - Appendix E – Offshore Transmission System and OTSDUW Plant and Apparatus Technical Design Criteria – PC.E.2 (Table)
      New Title for ER P28 Issue 2- Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom
      In the table column entitled "Reference No" Engineering Recommendation P28 should be modified to state Engineering Recommendation P28 Issue 2

- CONNECTION CONDITIONS
    - CC.6 Technical, Design and Operational Criteria
      Voltage Fluctuations CC6.1.7
      Please refer to Appendix B1

- EUROPEAN CONNECTION CONDITIONS
    - ECC.6 Technical, Design and Operational Criteria
      Voltage Fluctuations ECC.6.1.7
      Please refer to Appendix B2

- OPERATING CODES
    - OC5.5.4 Test And Monitoring Assessment (Test Criteria)
      In the parameter column the rows entitled *Voltage Fluctuation* and *Flicker* Engineering Recommendation P28 should be modified to state Engineering Recommendation P28 Issue 2

- SCHEDULE 7 – LOAD CHARACTERISTICS AT GRID SUPPLY POINTS
    - At the foot of the column entitled Data Description Engineering Recommendation P28 should be modified to state Engineering Recommendation P28 Issue 2

CONNECTION CONDITIONS
(CC)

CONTENTS

(This contents page does not form part of the Grid Code)

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 **GB Code User** connected to or seeking connection with the **National Electricity Transmission System**, or

(ii) **GB Code Users** in respect of **GB Generators** (other than in respect of **Small Power Stations**) or **GB Code User's** in respect of **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 **GB Code 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 those **GB Code Users** when undertaking **OTSDUW**.

(c) For the avoidance of doubt, the requirements of these **CC's** do not apply to **EU Code User's** for whom the requirements of the **ECC's** shall apply.

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 **GB Code Users**) to a **User's System** are similar for all **GB Code 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 an **GB Code 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 **GB 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 **GB Code Users**, which in the **CC** means:

(a) **GB 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 **GB Code 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 **GB Code 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 **GB 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 **GB 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 GB Code Users System** will be required to meet the applicable requirements of the Grid Code as though they are an **Onshore GB 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 **GB 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 **GB 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 Station**s 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

CC.6.3.15

CC.6.3.16

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 **GB Generator** or the **DC Converter Station** owner.

CC.3.4 In the case of **Offshore Embedded Power Stations** connected to an **Offshore GB Code 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 **GB 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 **GB Generator**. For the avoidance of doubt, requirements applicable to **GB Generators** undertaking **OTSDUW** and connecting to a **Network Operator's ~~User~~ System**, shall be consistent with those applicable requirements of **GB 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 **GB Code Users** prior to and during the course of **NGET** notifying the **GB Code User** that it has the right to become operational. The procedure for a **GB Code 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 **GB Code 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 **GB 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**.

CC.5.2.2 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 **GB Code 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 <u>TECHNICAL, DESIGN AND OPERATIONAL CRITERIA</u>

CC.6.1 <u>National Electricity Transmission System Performance Characteristics</u>

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 **GB Code 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 **GB Code 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 **GB Code 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:

Frequency Range	Requirement
51.5Hz - 52Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz.
51Hz - 51.5Hz	Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz.
49.0Hz - 51Hz	Continuous operation is required
47.5Hz - 49.0Hz	Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz.
47Hz - 47.5Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz.

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 **GB Code 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:

National Electricity Transmission System Nominal Voltage	Normal Operating Range
400kV	400kV ±5%
275kV	275kV ±10%
132kV	132kV ±10%

NGET and a **GB Code 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 **GB Code 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 **GB Code** and **EU Code Users' Plant** and **Apparatus** (and **OTSDUW Plant and Apparatus**) in relation to harmonic emissions. **GB Code 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 **Engineering Recommendation** P28 Issue 2 as current at the **Transfer Date** ~~Table CC.6.1.7 with the stated frequency of occurrence,~~ where:

~~(i)~~ $$\cancel{\%\Delta V_{steadystate} = \left| 100 \times \frac{\Delta V_{steadystate}}{V_0} \right|}$$

~~and~~

$$\cancel{\%\Delta V_{max} = 100 \times \frac{\Delta V_{max}}{V_0} ;}$$

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~~(ii) V_0 is the initial steady state system voltage;~~

~~(iii) $V_{steadystate}$ 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 $\Delta V_{steadystate}$ is the absolute value of the difference between $V_{steadystate}$ and V_0;~~

~~(iv) ΔV_{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;~~

(i~~viii~~) Voltage changes in C~~c~~ategory 3 ~~only occur infrequently, typically not planned more than once per year on average over the lifetime of a connection, and in circumstances~~ are typically 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

(ii~~x~~) For connections with a **Completion Date** after X ~~1st~~ XXXX~~September~~ 201X~~5~~ and where voltage changes would constitute a risk to the **National Electricity Transmission System** or, in **NGET**'s view, the **System** of any **GB Code User**, **Bilateral Agreements** may include provision for **NGET** to reasonably limit the number of voltage changes in C~~c~~ategory 2 or 3 to a lower number than specified in Table 4 of **Engineering Recommendation** P28 Issue 2 as current at the **Transfer Date** ~~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 4 ~~CC.6.1.7~~.

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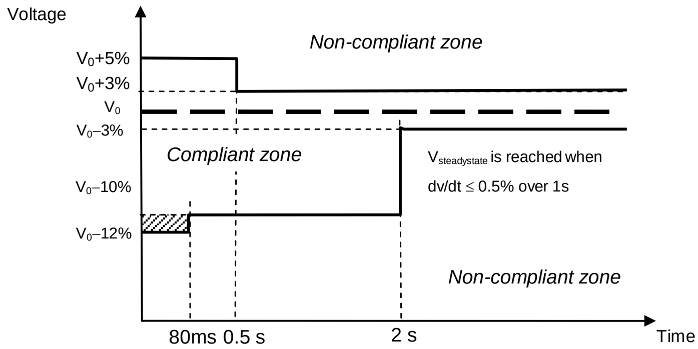
~~Category~~	~~Maximum number of Occurrences~~	~~$\%\Delta V_{max}$ & $\%\Delta V_{steadystate}$~~
~~1~~	~~No Limit~~	~~$\lvert\%\Delta V_{max}\rvert \leq 1\%$ & $\lvert\%\Delta V_{steadystate}\rvert \leq 1\%$~~
~~2~~	~~$\frac{3600}{\sqrt[0.304]{2.5 \times \%\Delta V_{max}}}$ occurrences per hour with events evenly distributed~~	~~$1\% < \lvert\%\Delta V_{max}\rvert \leq 3\%$ & $\lvert\%\Delta V_{steadystate}\rvert \leq 3\%$~~
~~3~~	~~No more than 4 per day for Commissioning, Maintenance and Fault Restoration~~	~~For decreases in voltage: $\%\Delta V_{max} \leq 12\%^1$ & $\%\Delta V_{steadystate} \leq 3\%$ For increases in voltage: $\%\Delta V_{max} \leq 5\%^2$ & $\%\Delta V_{steadystate} \leq 3\%$ (see Figure CC6.1.7)~~

~~Table CC.6.1.7 - Limits for Rapid Voltage Changes~~

~~[1] 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.~~

~~[2] An increase in voltage of up to 5% is permissible if it is reduced to up to 3% after 0.5 seconds.~~



~~Figure CC.6.1.7 -~~
~~Time and magnitude limits for a category 3 Rapid Voltage Change~~

(b) ~~For voltages above 132kV,~~ The limits for **Flicker Severity (Short Term)** ~~of 0.8 Unit~~ and a **Flicker Severity (Long Term)** ~~of 0.6 Unit, for voltages 132kV and below,~~ ~~**Flicker Severity (Short Term)** of 1.0 Unit and a **Flicker Severity (Long Term)**) of 0.8 Unit,~~ as set out in **Engineering Recommendation** P28 Issue 2 as current at the **Transfer Date**.

CC.6.1.8 Voltage fluctuations at a **Point of Common Coupling** 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

CC.6.1.9 **NGET** shall ensure that **GB Code Users' Plant and Apparatus** will not be subject to unacceptable Sub-Synchronous Oscillation conditions as specified in the relevant **Licence Standards**.

CC.6.1.10 **NGET** shall ensure where necessary, and in consultation with **Transmission Licensees** where required, that any relevant site specific conditions applicable at a **GB Code 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 **GB Code User's Bilateral Agreement**.

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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 **GB Code User** must ensure are complied with in relation to its **Plant** and **Apparatus** and which in the case of CC.6.2.2.2.2, 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 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 **GB Code 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 **GB Code 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 or in ECC.6.2.1.2 (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 **GB Code User** or **EU Code User** (as applicable) 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**.

(c) Where the **GB Code User** provides **NGET** with information and/or test reports in respect of **Plant** and/or **Apparatus** which the **GB Code 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 an **GB Code 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 **GB 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 GB 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 **GB 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 **GB 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 **GB 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 **GB Code User** or **NGET** or the **GB 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 **GB 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 **GB Generators** or **DC Converter Station** owners or **GB 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 **GB Code 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 **GB 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 **GB 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 **GB Generator** (including in the case of **OTSDUW Plant and Apparatus**) or **DC Converter** is connected at 132kV and below. This will permit **Discrimination** between **GB 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 **GB 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 **GB Generator's System**, or **DC Converter Station** owner's **System**, as the case may be, circuit breaker fail **Protection** shall be provided by the **GB 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 **GB Generator** or **DC Converter Station** owner will install circuit breaker fail **Protection** equipment in accordance with the requirements of the **Bilateral Agreement**. The **GB 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 **GB 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 **GB Generators** to fit pole-slipping **Protection** on their **Generating Units**.

CC.6.2.2.3.5 Signals for Tariff Metering

GB 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 **GB 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 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 **GB Code 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 **GB Code User's** connection voltage, the **GB Code User** must provide **NGET** with the means of tripping all the **GB Code User's** circuit breakers necessary to isolate faults or **System** abnormalities on the **National Electricity Transmission System**. In these circumstances, for faults on the **GB Code User's System**, the **GB Code 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 **GB Code 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 **GB 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 **GB 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 **GB 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** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** will apply at all **Active Power** output levels above 50% of the **Rated MW** output 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.

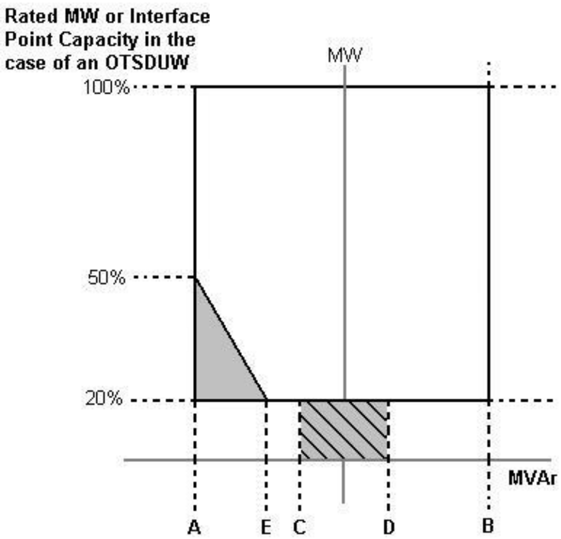


Figure 1

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 GB Generators** or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for **GB 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 **GB 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 **GB 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 **GB 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**.

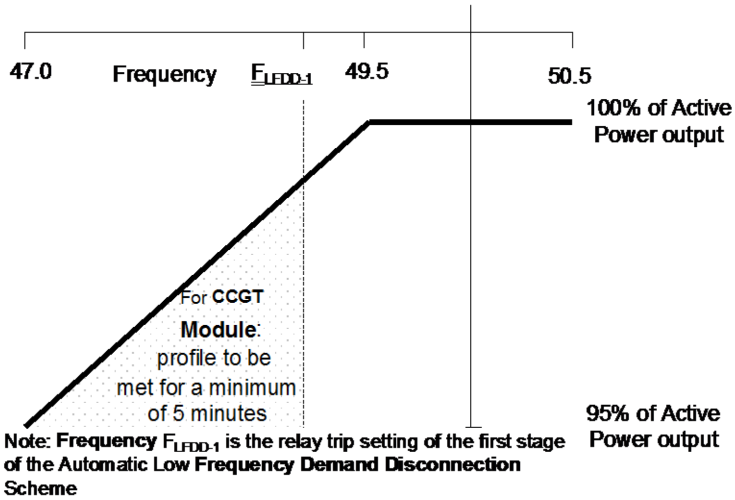


Figure 2

(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%.

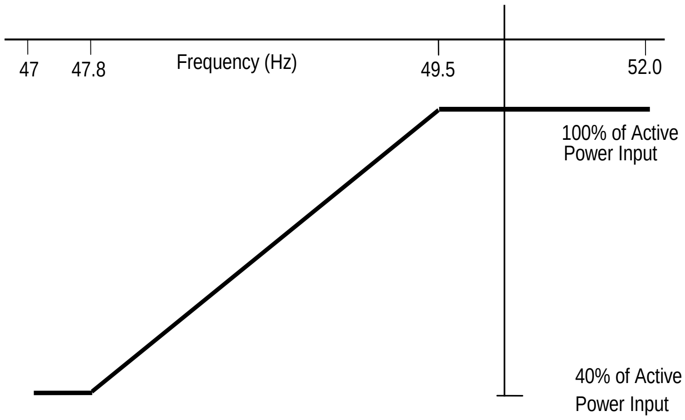


Figure 3

(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 **GB Generator** shall comply with the requirements of CC.6.3.3. **GB 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 **GB Generators** to fulfil their obligations.

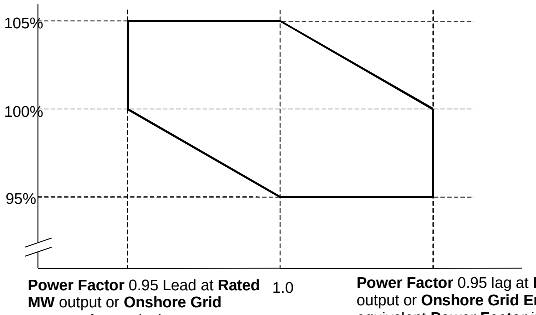
(f) In the case of an **OTSDUW DC Converter** the **OTSDUW Plant and Apparatus** shall provide a continuous signal indicating the real time frequency measured at the **Interface Point** to the **Offshore Grid Entry Point**.

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 **GB 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 **GB Code 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**.

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 **GB 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;

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

<u>Excitation and Voltage Control Performance Requirements</u>

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 **GB Code 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**, **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 **GB Code 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.

<u>Steady state Load Inaccuracies</u>

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.

<u>Negative Phase Sequence Loadings</u>

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**.

<u>Neutral Earthing</u>

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.

<u>Frequency Sensitive Relays</u>

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**.

CC.6.3.13 **GB 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 **GB Generator** or **DC Converter Station** owner to decide whether to disconnect his **Apparatus** for reasons of safety of **Apparatus**, **Plant** and/or personnel.

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

CC.6.3.15 Fault Ride Through

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**, **Onshore Power Park Modules**, **Onshore 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 GB Generators** in respect of **Offshore Generating Units** at a **Large Power Station**, **Offshore Power Park Modules** at a **Large Power Station** and **DC Converter Station** owners in respect of **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 GB 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**).

CC.6.3.15.1 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 **Onshore 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 **Onshore Generating Units** or **Onshore 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,

NOT TO SCALE

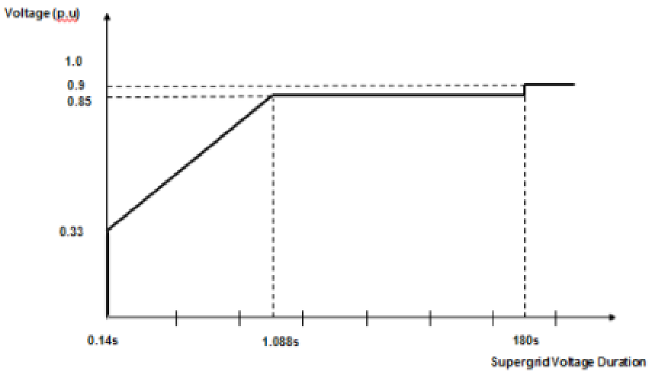


Figure 5a

(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,

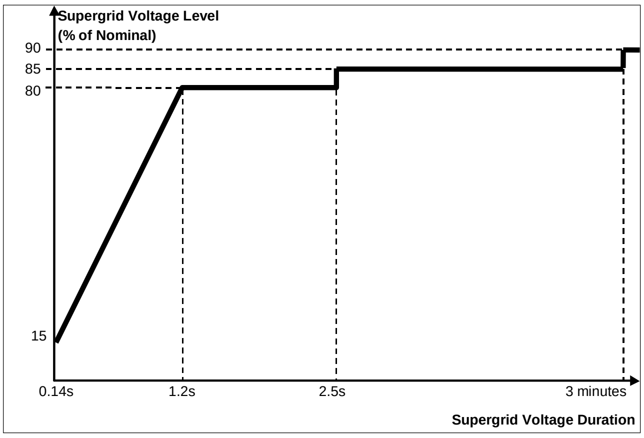


Figure 5b

(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 **Onshore 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.

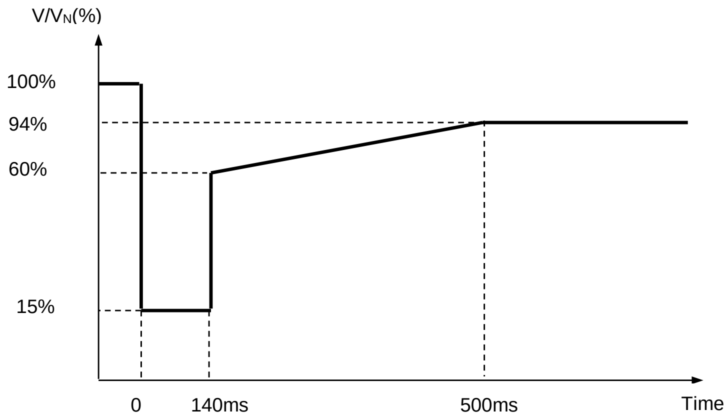


Figure 6

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;

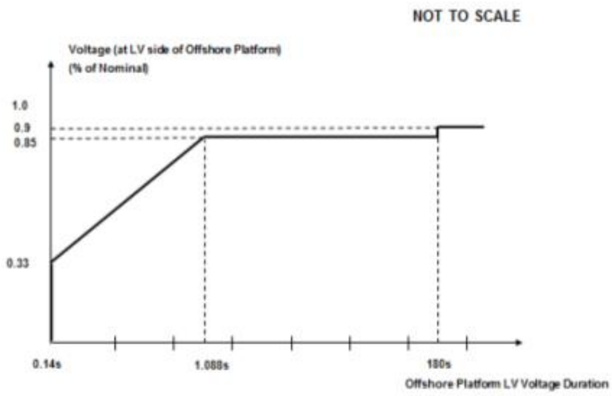
(iii) Each **Offshore DC Converter** shall be designed to meet the **Active Power** recovery characteristics as specified in the **Bilateral Agreement** upon restoration of the voltage at the **LV Side of the Offshore Platform**.

(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.

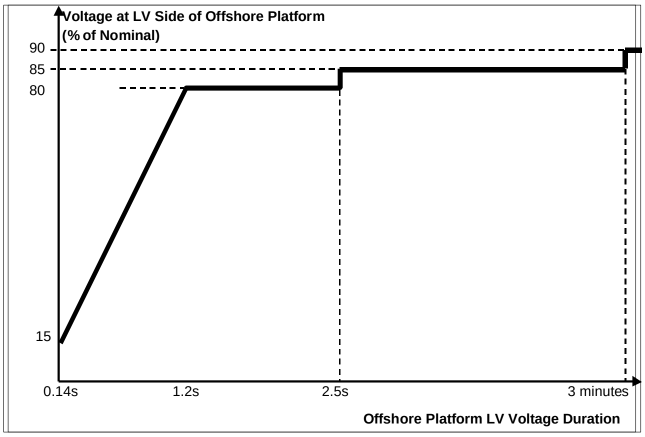


Figure 7b

(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 **GB Code 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 **GB 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 **GB 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 **GB 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**.

CC.6.5 Communications Plant

CC.6.5.1 In order to ensure control of the **National Electricity Transmission System**, telecommunications between **GB Code 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.

CC.6.5.2 Control Telephony and System Telephony

CC.6.5.2.1 **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**.

CC.6.5.2.2 **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**.

CC.6.5.2.3 Calls made and received over **Control Telephony** and **System Telephony** may be recorded and subsequently replayed for commercial and operational reasons.

CC.6.5.3 Supervisory Tones

CC.6.5.3.1 **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.

CC.6.5.3.2 **System Telephony** supervisory tones indicate to the calling and receiving parties dial, engaged and ringing tones.

CC.6.5.4 Obligations in respect of Control Telephony and System Telephony

CC.6.5.4.1 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 **GB Code User's Control Point** where the **GB Code 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**.

CC.6.5.4.2 Where in **NGET's** sole opinion the installation of **Control Telephony** is not practicable at a **GB Code 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 **GB Code User** shall ensure that **System Telephony** is installed.

CC.6.5.4.3 Where **System Telephony** is installed, **GB Code 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**.

CC.6.5.4.4 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 **GB Code User** and **NGET** shall use reasonable endeavours to agree a test programme and where **NGET** requests the assistance of the **GB Code User** in performing the agreed test programme the **User** shall provide such assistance.

CC.6.5.4.5 **Control Telephony** and **System Telephony** shall only be used for the purposes of operational voice communication between **NGET** and the relevant **User**.

CC.6.5.4.6 **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 **GB Code Users** shall only use such priority call functionality for urgent operational communications.

CC.6.5.5 Technical Requirements for Control Telephony and System Telephony

CC.6.5.5.1 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 **GB Code Users**, this will be provided, where possible, by **NGET**.

CC.6.5.5.2 **System Telephony** shall consist of a dedicated Public Switched Telephone Network telephone line that shall be installed and configured by the relevant **GB Code User**. **NGET** shall provide a dedicated free phone number (UK only), for the purposes of receiving incoming calls to **NGET**, which **GB Code Users** shall utilise for **System Telephony**. **System Telephony** shall only be utilised by the **NGET Control Engineer** and the **GB Code User's Responsible Engineer/Operator** for the purposes of operational communications.

Operational Metering

CC.6.5.6 (a) **NGET** shall provide system control and data acquisition (SCADA) outstation interface equipment. The **GB Code 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 **GB Code 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 **GB 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 **GB Code User** that wishes to participate in the **Balancing Mechanism**;

or

(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 **GB Code User** and **NGET** shall provide a facsimile machine or machines:

(a) in the case of **GB 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 **GB Code User** shall notify, prior to connection to the **System** of the **GB Code 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 **GB Code User's Plant** and **Apparatus NGET** shall notify each **GB Code 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 **GB 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 **GB 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 **GB 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 **GB Code 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 **GB Code User** or from **OTSDUW Plant and Apparatus**, **NGET** will inform the **GB Code User** and they will be provided by the **GB Code User** with both the timing of the installation of the equipment for receiving such signals and its exact position being agreed (the **GB Code 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 **GB Code 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 **GB Code 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 **GB Code 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 **GB Code 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 **GB Generator** or **DC Converter 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 **GB Code 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 **GB Code 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 **Users** 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 **GB Code 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 **Relevant Transmission Licensee** when working on its **Plant** and **Apparatus**, that does not imply that the **Relevant Transmission Licensee'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.

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**.

<u>Gas Zone Diagrams</u>

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**.

<u>Preparation of Operation and Gas Zone Diagrams for Users' Sites and Transmission Interface Sites</u>

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.

<u>Preparation of Operation and Gas Zone Diagrams for Transmission Sites</u>

CC.7.4.10 In the case of an **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

CC.7.4.13.1 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**.

CC.7.4.13.2 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**.

CC.7.4.13.3 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

CC.7.4.14 (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 **OTSDUW**, each **Interface Point**) and will include **Connection Site** (and in the case of **OTSDUW**, **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

CC.7.5.2 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 **OTSDUW 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 **OTSDUW**, 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**.

CC.7.5.3 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** .

<u>Preparation of Site Common Drawings for a Transmission Site</u>

CC.7.5.4 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**.

CC.7.5.5 **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**.

CC.7.5.6 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.

CC.7.5.7 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** (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

CC.7.5.8 (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**.

CC.7.9 **GB 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.

CC.8 ANCILLARY SERVICES

CC.8.1 System Ancillary Services

The **CC** contain requirements for the capability for certain **Ancillary Services**, which are needed for **System** reasons ("**System Ancillary Services**"). There follows a list of these **System Ancillary Services**, together with the paragraph number of the **CC** (or other part of the **Grid Code**) in which the minimum capability is required or referred to. The list is divided into two categories: Part 1 lists the **System Ancillary Services** which

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

(b) GB **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) **GB 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 **GB 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**

CC.8.2 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 **GB Code 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 **GB Code 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 **GB Code 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 **GB Code 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 an **GB Code 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**.

[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 15th October 2004. In Scotland or **Offshore**, from a date to be agreed between **NGET** and **the Relevant Transmission Licensee**.

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.

Urgent Changes

CC.A.1.1.15 When an **GB Code 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 **GB Code User** shall notify **NGET**, or **NGET** shall notify the **GB Code 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 **GB Code Users** and signed on behalf of **NGET** and **GB Code Users** (by the persons referred to in CC.A.1.1.9) as soon as possible after it has been prepared and sent to **GB Code Users** for confirmation.

Responsible Managers

CC.A.1.1.16 Each **GB Code 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 **GB Code User** and **NGET** shall, prior to the **Completion Date** under each **Bilateral Agreement** and/or **Construction Agreement**, supply to that **GB Code 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 **GB Code 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: _______________

			SAFETY		OPERATIONS			
ITEM OF PLANT/ APPARATUS	PLANT APPARATUS OWNER	SITE MANAGER	SAFETY RULES	CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY CO-ORDINATOR	OPERATIONAL PROCEDURES	CONTROL OR OTHER RESPONSIBLE ENGINEER	PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION & MAINTENANCE	REMARKS

PAGE: _______________ ISSUE NO: _______________ DATE: _______________

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

_____________________ AREA

COMPLEX: _____________________ SCHEDULE: _____________________

CONNECTION SITE: _____________________

ITEM OF PLANT/ APPARATUS	PLANT APPARATUS OWNER	SITE MANAGER	SAFETY		OPERATIONS		PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION & MAINTENANCE	REMARKS
			SAFETY RULES	CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY CO-ORDINATOR	OPERATIONAL PROCEDURES	CONTROL OR OTHER RESPONSIBLE ENGINEER		

NOTES:

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

PAGE: __________ ISSUE NO: __________ DATE: __________

SP TRANSMISSION Ltd
SITE RESPONSIBILITY SCHEDULE
OWNERSHIP, MAINTENANCE AND OPERATIONS OF EQUIPMENT
IN JOINT USER SITUATIONS

Network Area:

Sheet No.
Revision:
Date:

SECTION 'A' BUILDING AND SITE

OWNER		ACCESS REQUIRED:-	
LESSEE			
MAINTENANCE		SPECIAL CONDITIONS:-	
SAFETY			
SECURITY		LOCATION OF SUPPLY TERMINALS:-	

SECTION 'B' CUSTOMER OR OTHER PARTY

NAME:-	
ADDRESS:-	
TEL NO:-	
SUB STATION:-	
LOCATION:-	

SECTION 'C' PLANT

ITEM Nos.	EQUIPMENT	IDENTIFICATION	OWNER	SAFETY RULES APPLICABLE	OPERATION				MAINTENANCE		FAULT INVESTIGATION			TESTING		RELAY SETTINGS	REMARKS
					Tripping	Closing	Isolating	Earthing	Primary Equip.	Protection Equip.	Primary Equip.	Protection Equip.	Reclosure	Trip and Alarm	Primary Equip.		

SECTION 'D' CONFIGURATION AND CONTROL

ITEM Nos.	CONFIGURATION RESPONSIBILITY	TELEPHONE NUMBER	REMARKS
ITEM Nos.	CONTROL RESPONSIBILITY	TELEPHONE NUMBER	REMARKS

SECTION 'E' ADDITIONAL INFORMATION

ABBREVIATIONS:-
D - SP AUTHORISED PERSON - DISTRIBUTION SYSTEM
NGC - NATIONAL GRID COMPANY
SPD - SP DISTRIBUTION Ltd
SPPS - POWERSYSTEMS
SPT - SP TRANSMISSION Ltd
ST - SCOTTISH POWER TELECOMMUNICATIONS
T - SP AUTHORISED PERSON - TRANSMISSION SYSTEM
U - USER

SIGNED ____________ FOR SP Transmission DATE ____________

SIGNED ____________ FOR SP Distribution DATE ____________

SIGNED ____________ FOR PowerSystems/User DATE ____________

Scottish Hydro-Electric Transmission Limited

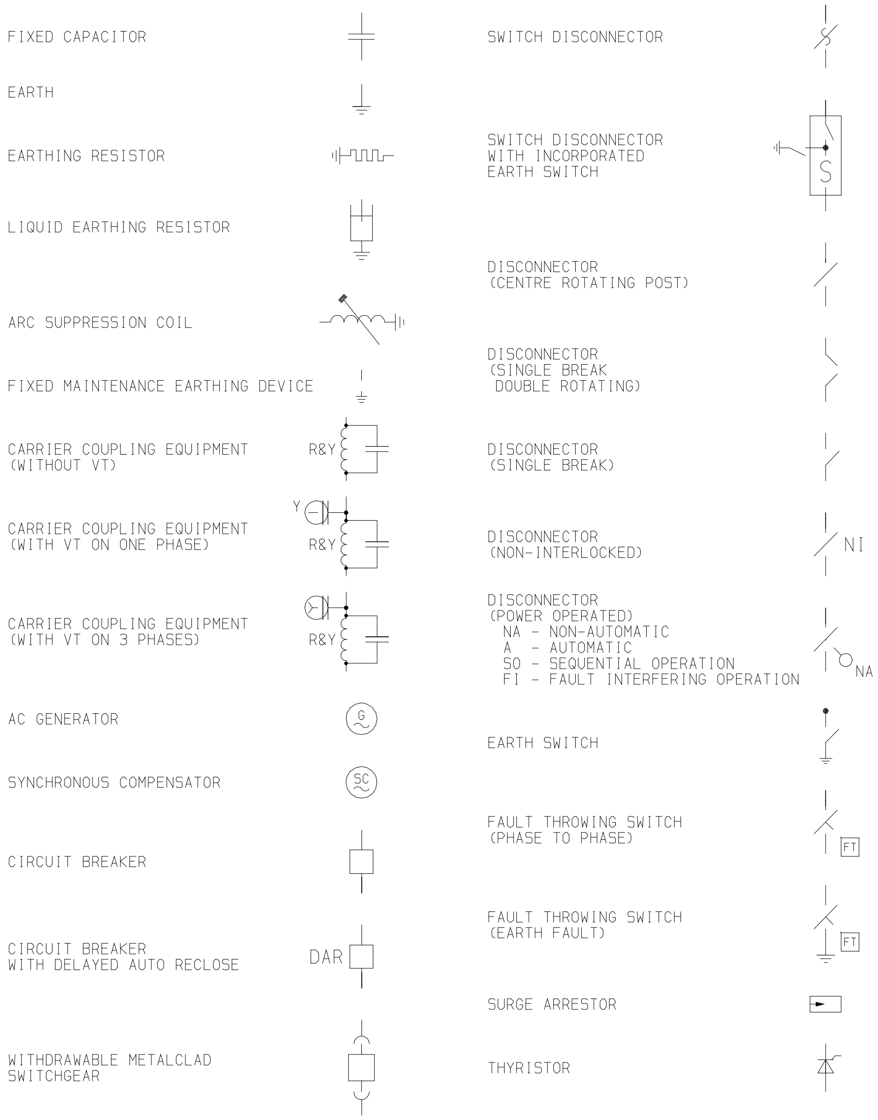
Site Responsibility Schedule

Substation Type: ______ Number: ______ Revision: ______

Equipment	Owner	Controller	Maintainer	Responsible System User	Responsible Management Unit	Control Authority	Safety Rules	Operational Procedures	Notes

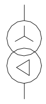
APPENDIX 2 - OPERATION DIAGRAMS

PART 1A - PROCEDURES RELATING TO OPERATION DIAGRAMS

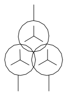


TRANSFORMERS
(VECTORS TO INDICATE
WINDING CONFIGURATION)

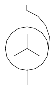
TWO WINDING



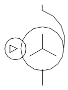
THREE WINDING



AUTO

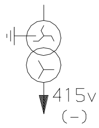


AUTO WITH DELTA TERTIARY



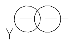
EARTHING OR AUX. TRANSFORMER

(-) INDICATE REMOTE SITE
IF APPLICABLE

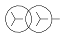


VOLTAGE TRANSFORMERS

SINGLE PHASE WOUND



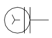
THREE PHASE WOUND



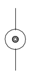
SINGLE PHASE CAPACITOR

TWO SINGLE PHASE CAPACITOR

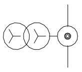
THREE PHASE CAPACITOR



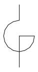
* CURRENT TRANSFORMER
(WHERE SEPARATE PRIMARY
APPARATUS)



* COMBINED VT/CT UNIT
FOR METERING



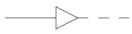
REACTOR



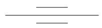
* BUSBARS

* OTHER PRIMARY CONNECTIONS

* CABLE & CABLE SEALING END

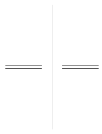


* THROUGH WALL BUSHING



* BYPASS FACILITY

* CROSSING OF CONDUCTORS
(LOWER CONDUCTOR
TO BE BROKEN)

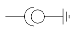


PREFERENTIAL ABBREVIATIONS

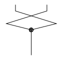
AUXILIARY TRANSFORMER	Aux T
EARTHING TRANSFORMER	ET
GAS TURBINE	Gas T
GENERATOR TRANSFORMER	Gen T
GRID TRANSFORMER	Gr T
SERIES REACTOR	Ser Reac
SHUNT REACTOR	Sh Reac
STATION TRANSFORMER	Stn T
SUPERGRID TRANSFORMER	SGT
UNIT TRANSFORMER	UT

* NON-STANDARD SYMBOL

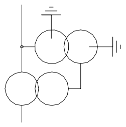
PORTABLE MAINTENANCE
EARTH DEVICE



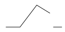
DISCONNECTOR
(PANTOGRAPH TYPE)



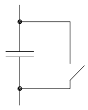
QUADRATURE BOOSTER



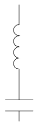
DISCONNECTOR
(KNEE TYPE)



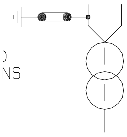
SHORTING/DISCHARGE SWITCH



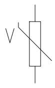
CAPACITOR
(INCLUDING HARMONIC FILTER)



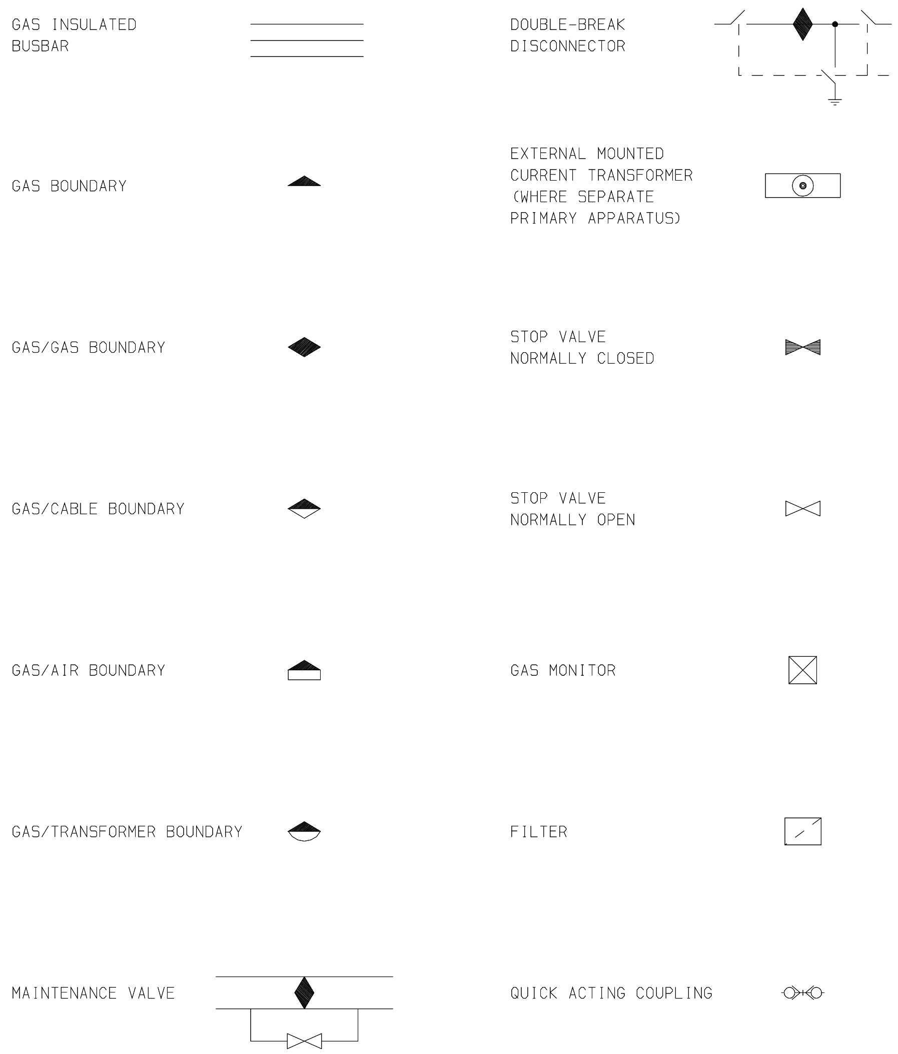
SINGLE PHASE TRANSFORMER(BR)
NEUTRAL AND PHASE CONNECTIONS



RESISTOR WITH INHERENT
NON-LINEAR VARIABILITY,
VOLTAGE DEPENDANT



PART 1B - PROCEDURES RELATING TO GAS ZONE DIAGRAMS



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

(22) Single Phase VT & Phase Identity

(23) High Accuracy VT and Phase Identity

(24) Surge Arrestors/Diverters

(25) Neutral Earthing Arrangements on HV Plant

(26) Fault Throwing Devices

(27) Quadrature Boosters

(28) Arc Suppression Coils

(29) Single Phase Transformers (BR) Neutral and Phase Connections

(30) Current Transformers (where separate plant items)

(31) Wall Bushings

(32) Combined VT/CT Units

(33) Shorting and Discharge Switches

(34) Thyristor

(35) Resistor with Inherent Non-Linear Variability, Voltage Dependent

(36) Gas Zone

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** on or 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).

CC.A.3.4 Testing Of Frequency Response Capability

The response capabilities shown diagrammatically in Figure CC.A.3.1 are measured by taking the responses as obtained from some of the dynamic response tests specified by **NGET** and carried out by **GB 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.

CC.A.3.5 Repeatability Of Response

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

Figure CC.A.3.1 - Minimum Frequency Response Requirement Profile for a 0.5 Hz frequency change from Target Frequency

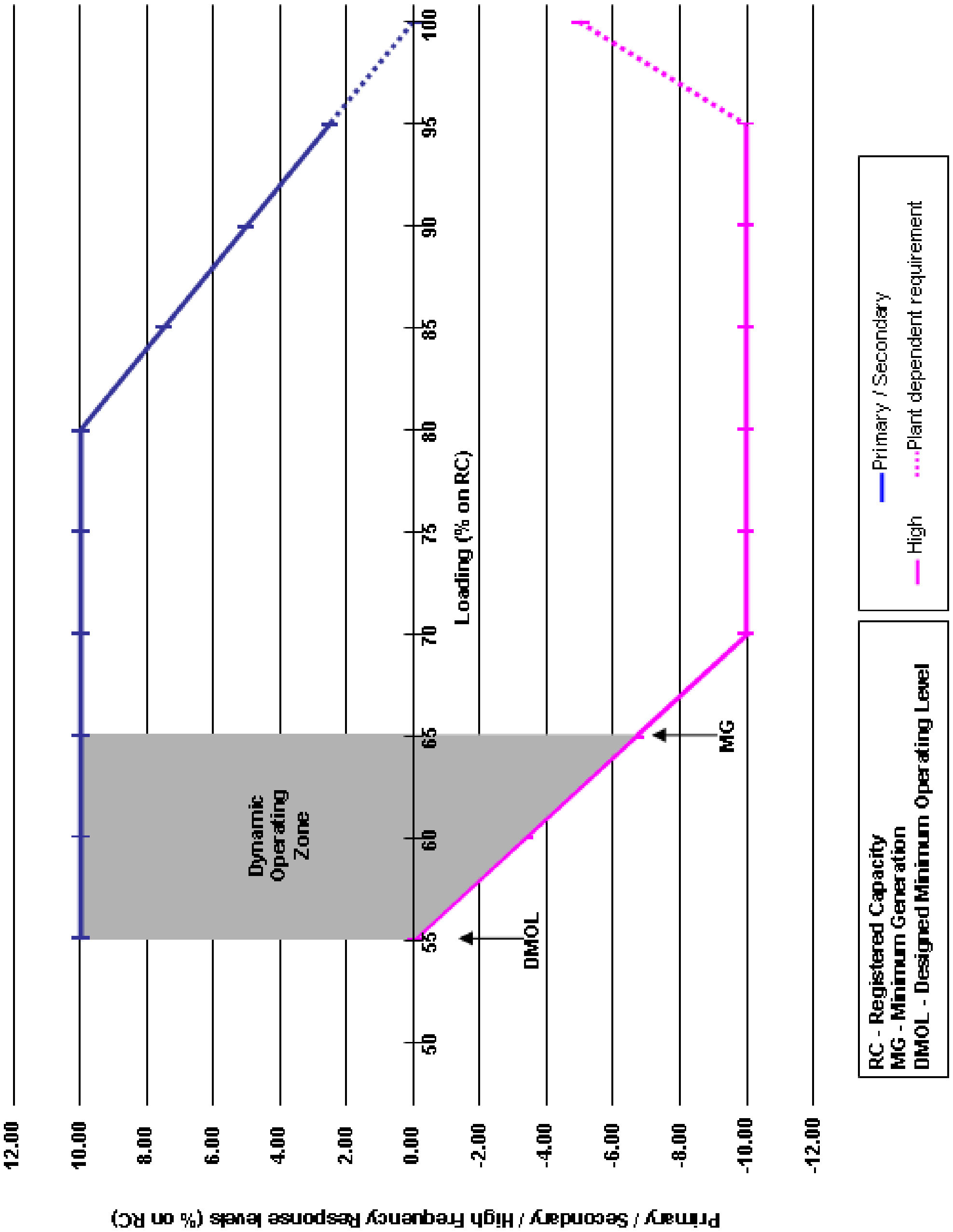


Figure CC.A.3.2 - Interpretation of Primary and Secondary Response Values

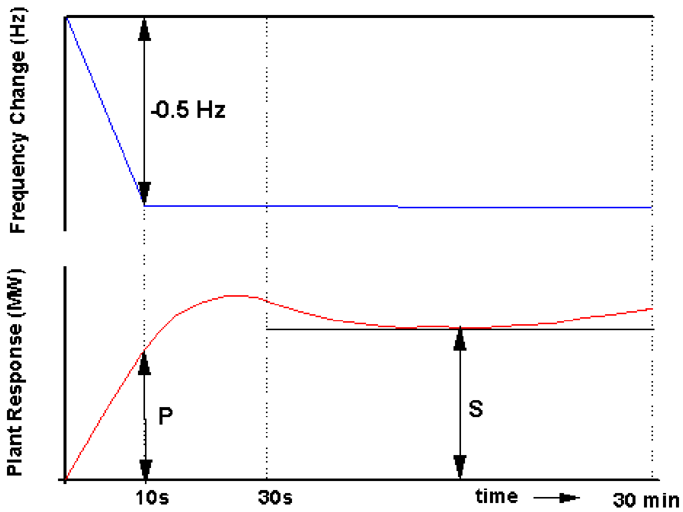
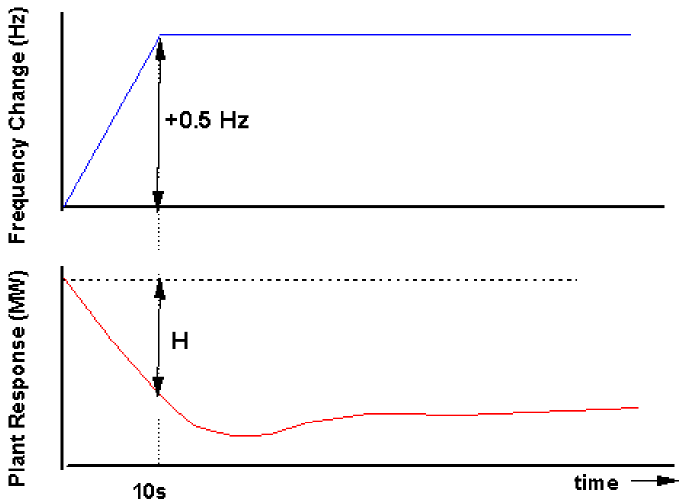


Figure CC.A.3.3 - Interpretation of High Frequency Response Values



APPENDIX 4 - 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.

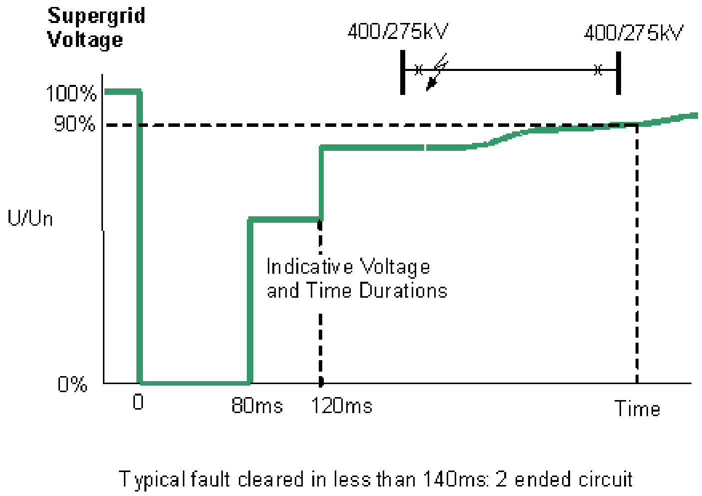


Figure CC.A.4A.1 (a)

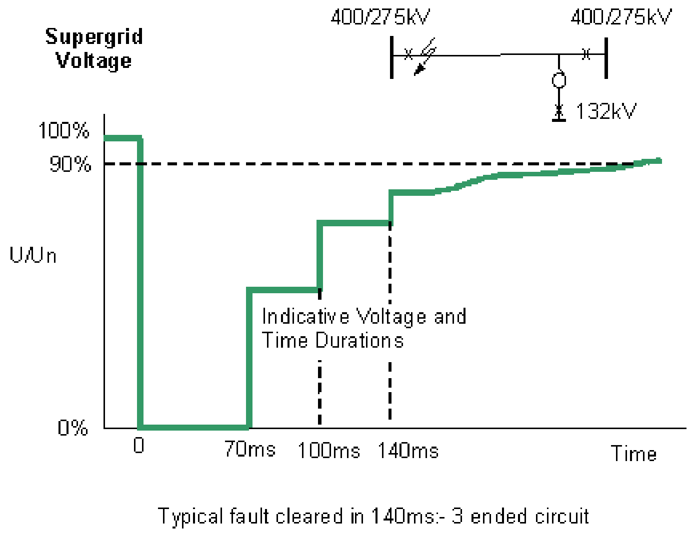


Figure CC.A.4A.1 (b)

CC.A.4A.3 <u>Supergrid Voltage Dips On The Onshore Transmission System Greater Than 140ms In Duration</u>

CC.A.4A3.1 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.4A3.1 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.4A3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

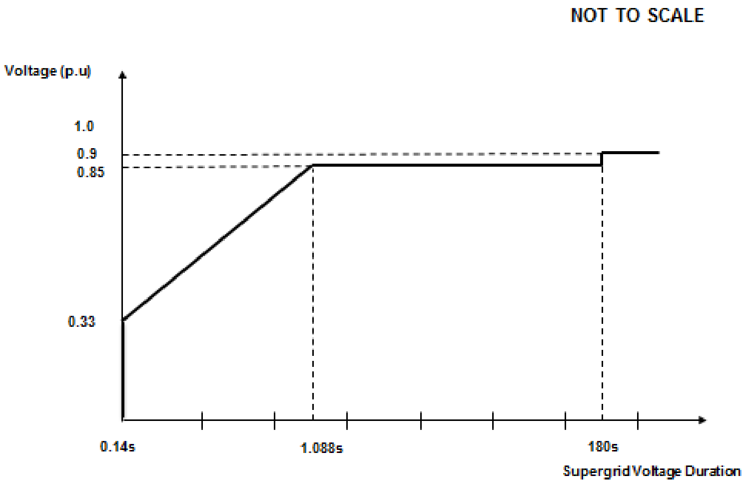


Figure CC.A.4A3.1

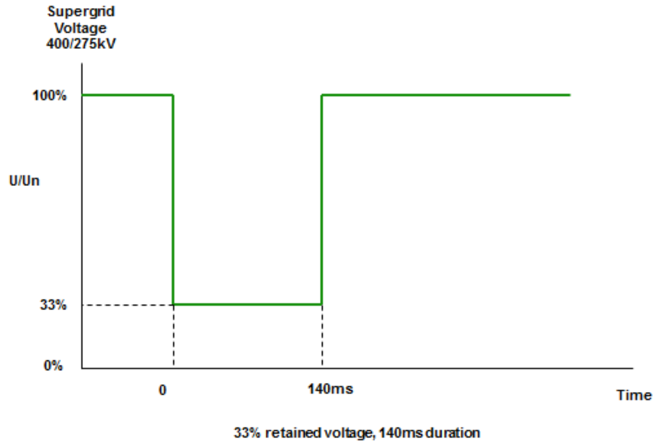
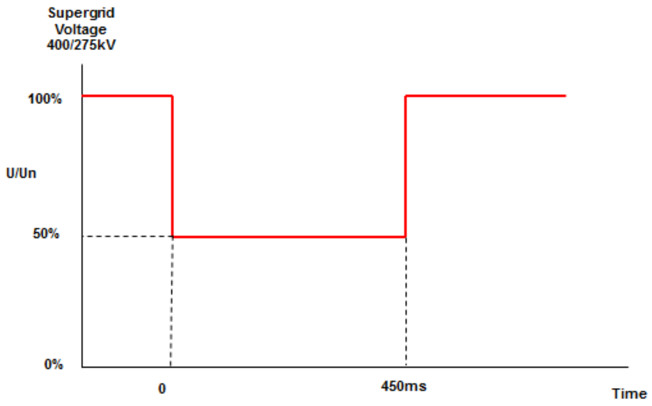
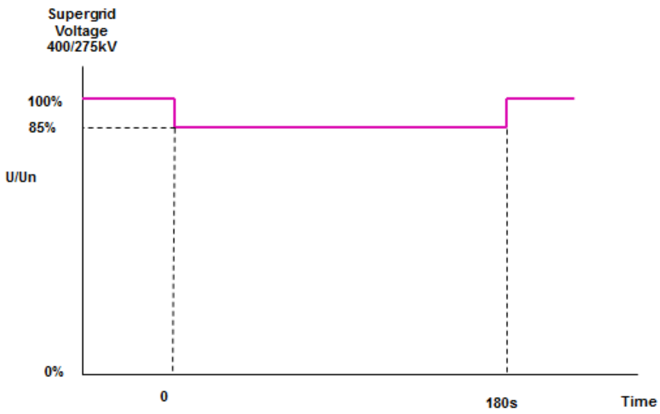


Figure CC.A.4A3.2 (a)



50% retained voltage, 450ms duration

Figure CC.A.4A3.2 (b)



85% retained voltage, 180s duration

Figure CC.A.4A3.2 (c)

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.

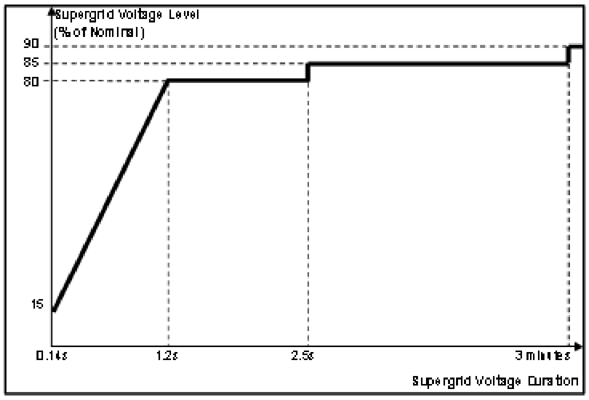


Figure CC.A.4A3.3

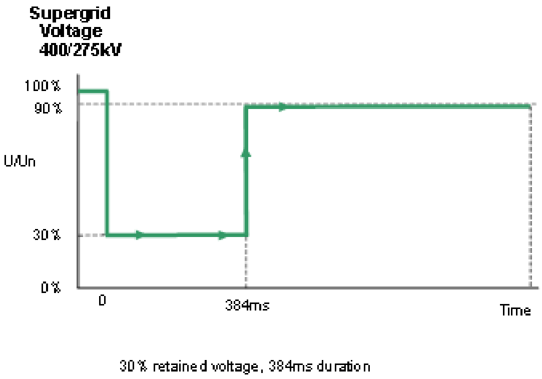
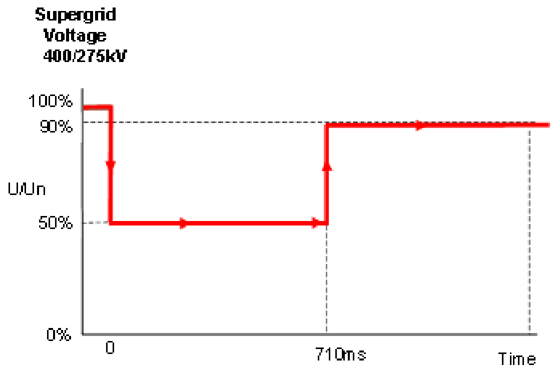
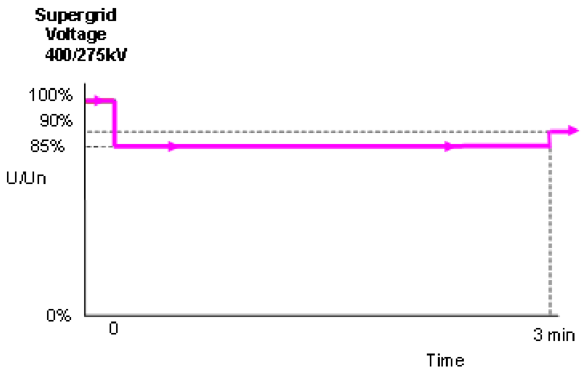


Figure CC.A.4A3.4 (a)



50% retained voltage, 710ms duration

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



85% retained voltage, 3 minutes duration

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

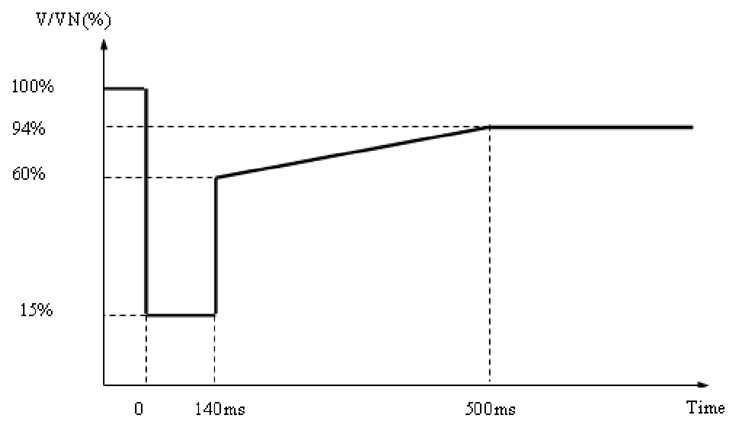
APPENDIX 4B - FAULT RIDE THROUGH REQUIREMENTS FOR OFFSHORE GENERATING UNITS IN A LARGE POWER STATION, OFFSHORE POWER PARK MODULES IN A LARGE POWER STATION AND OFFSHORE DC CONVERTERS IN A LARGE POWER STATION WHICH SELECT TO MEET THE FAULT RIDE THROUGH REQUIREMENTS AT THE LV SIDE OF THE OFFSHORE PLATFORM 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

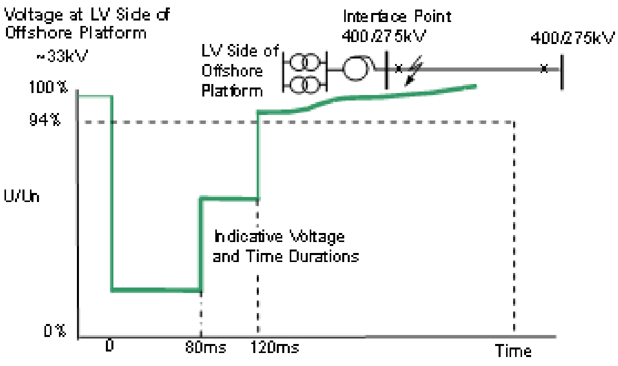
For voltage dips on the **LV Side of the Offshore Platform** which last up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15.2 (a) (i). This includes Figure 6 which is reproduced here in Figure CC.A.4B.1. The purpose of this requirement is to translate the conditions caused 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**.



V/V_N 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**.

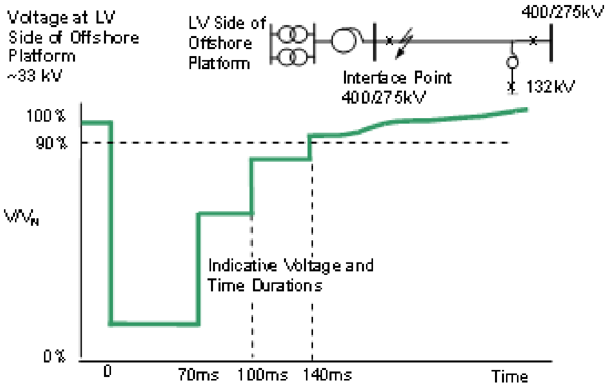
Figure CC.A.4B.1

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**.



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

Figure CC.A.4B.2 (a)



Typical fault cleared in 140ms:- 3 ended circuit

Figure CC.A.4B.2 (b)

CCA.4B.3 <u>Voltage Dips Which Occur On The **LV Side Of The Offshore Platform** Greater Than 140ms In Duration</u>

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.

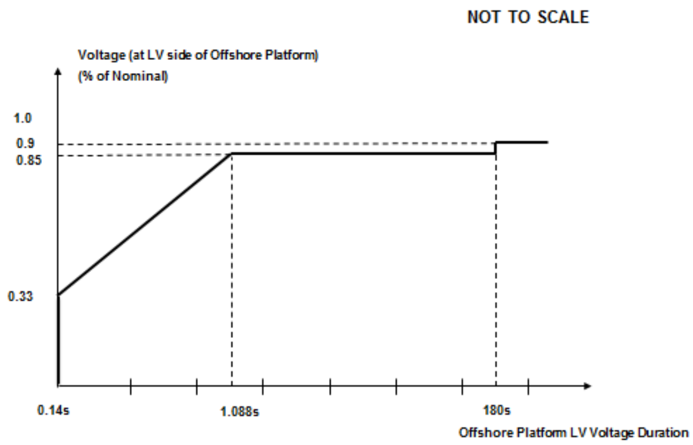


Figure CC.A.4B3.1

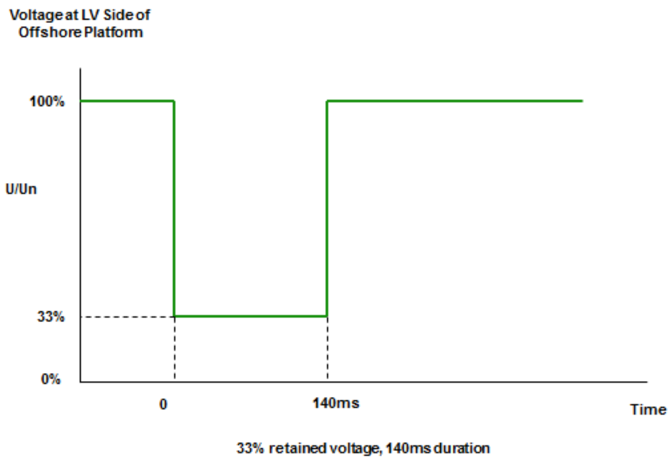


Figure CC.A.4B3.2 (a)

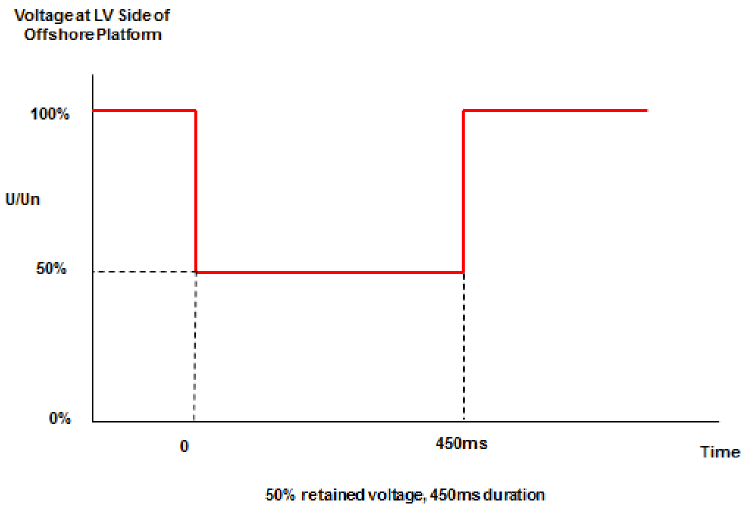


Figure CC.A.4B3.2 (b)

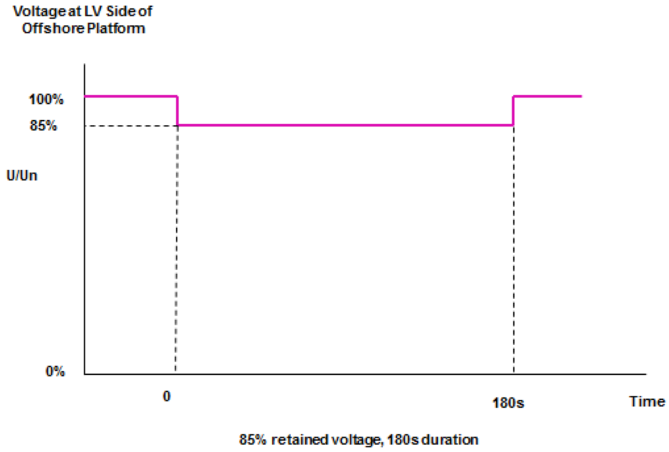


Figure CC.A.4B3.2 (c)

CC.A.4B.3.2 <u>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.</u>

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.

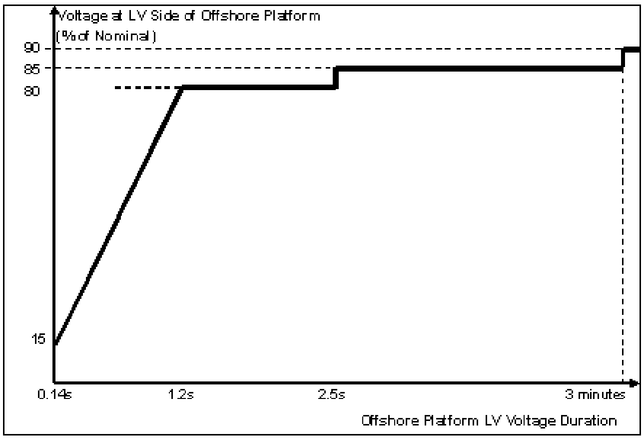


Figure CC.A.4B.4

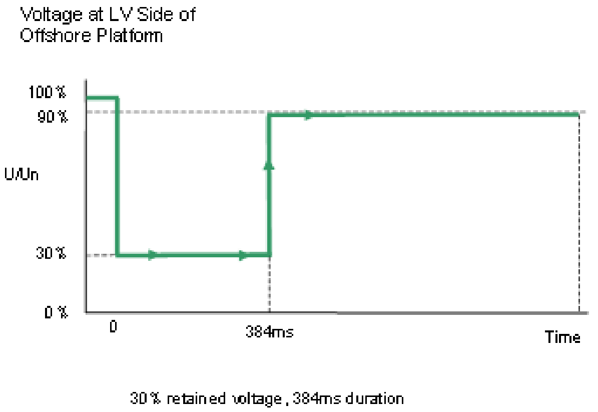


Figure CC.A.4B.5 (a)

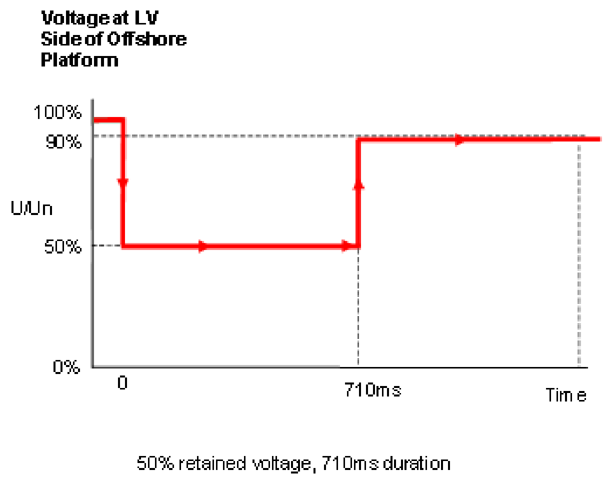


Figure CC.A.4B.5(b)

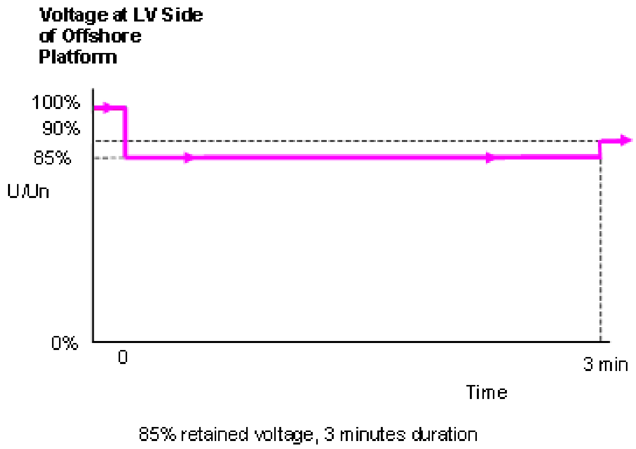


Figure CC.A.4B.5(c)

APPENDIX 5 - TECHNICAL REQUIREMENTS
LOW FREQUENCY RELAYS FOR THE AUTOMATIC DISCONNECTION OF SUPPLIES AT LOW FREQUENCY

CC.A.5.1 Low Frequency Relays

CC.A.5.1.1 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 1st 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 1st 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.

Frequency Hz	% **Demand** disconnection for each Network Operator in Transmission Area		
	NGET	SPT	SHETL
48.8	5		
48.75	5		
48.7	10		
48.6	7.5		10
48.5	7.5	10	
48.4	7.5	10	10
48.2	7.5	10	10
48.0	5	10	10
47.8	5		
Total % **Demand**	60	40	40

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.

APPENDIX 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 **GB Code 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 6. 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 **GB 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 **GB 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 **GB 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 **GB 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 **GB 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 **GB 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 **GB Code 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 **GB 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 **GB 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.

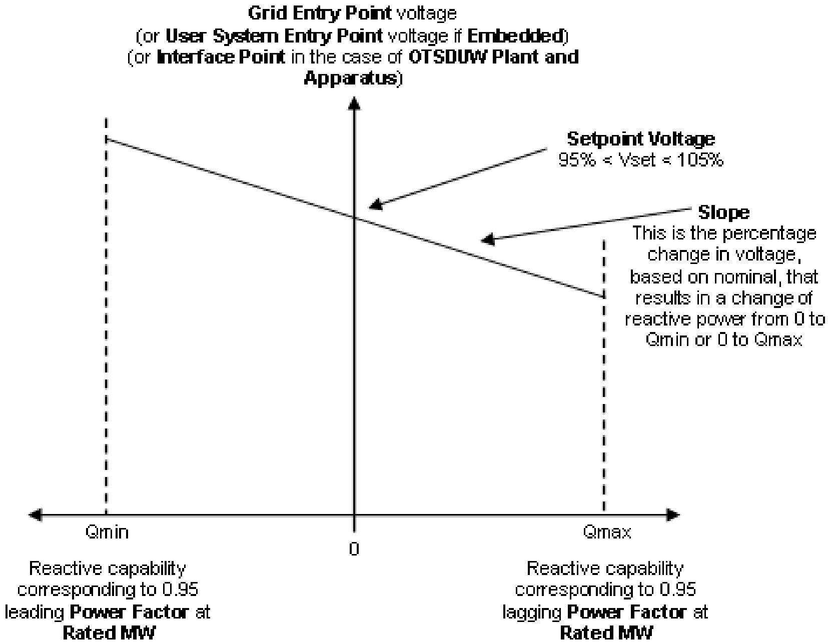


Figure CC.A.7.2.2a

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 **GB Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%. For **Embedded GB 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 **GB Generator** to implement an alternative slope setting within the range of 2% to 7%. For **Embedded GB 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.

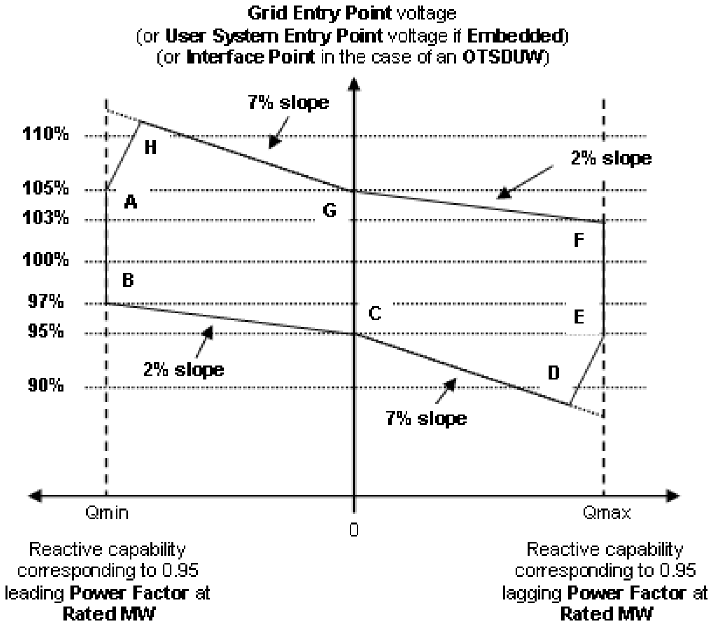


Figure CC.A.7.2.2b

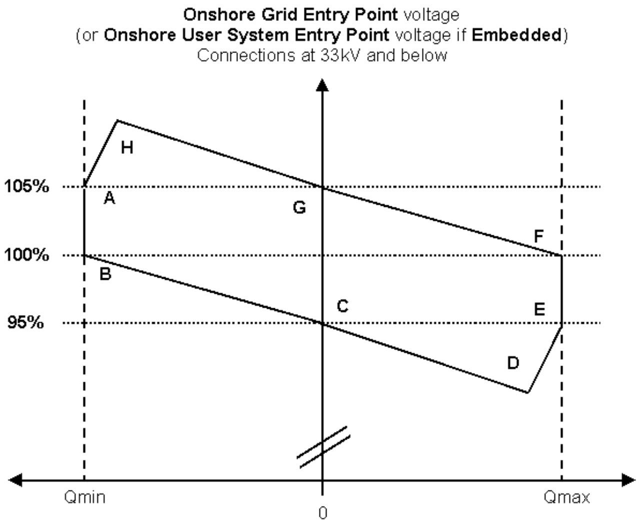


Figure CC.A.7.2.2c

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** voltage 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 **GB Code 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.

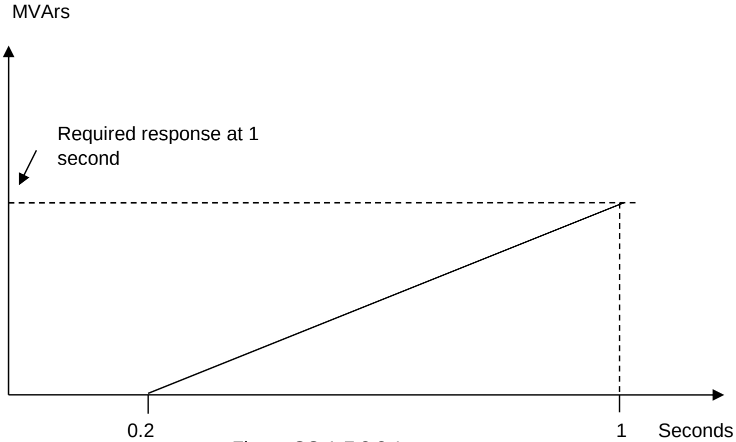


Figure CC.A.7.2.3.1a

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 <u>Power Oscillation Damping</u>

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 **GB Generator** will provide to **NGET** a report covering the areas specified in CP.A.3.2.2.

CC.A.7.2.5 <u>Overall Voltage Control System Characteristics</u>

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 >

EUROPEAN CONNECTION CONDITIONS

(ECC)

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(This contents page does not form part of the Grid Code)

ECC.1 INTRODUCTION

ECC.1.1 The **European Connection Conditions** ("**ECC**") specify both:

(a) the minimum technical, design and operational criteria which must be complied with by:

(i) any **EU Code User** connected to or seeking connection with the **National Electricity Transmission System**, or

(ii) **EU Generators** or **HVDC System Owners** connected to or seeking connection to a **User's System** which is located in **Great Britain** or **Offshore**, and

(iii) **Network Operators** but only in respect of ECC.3.1(f) and (g) alone.

(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 **ECC** also specify the minimum technical, design and operational criteria which must be complied with by the **User** when undertaking **OTSDUW**.

(c) The requirements of **European Regulation (EU) 2016/631** shall not apply to

1. **Power Generating Modules** that are installed to provide backup power and operate in parallel with the **Total System** for less than 5 minutes per calendar month while the **System** is in normal state. Parallel operation during maintenance or commissioning of tests of that **Power Generating Module** shall not count towards that five minute limit.

2. **Power Generating Modules** connected to the **Transmission System** or **Network Operators System** which are not operated in synchronism with a **Synchronous Area**.

3. **Power Generating Modules** that do not have a permanent **Connection Point** or **User System Entry Point** and used by **NGET** to temporarily provide power when normal **System** capacity is partly or completely unavailable.

ECC.2 OBJECTIVE

ECC.2.1 The objective of the **ECC** 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 and European Regulations.

ECC.2.2 In the case of any **OTSDUW** the objective of the **ECC** 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.

ECC.2.3 Provisions of the **ECC** 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 **ECC** applying in relation to the relevant **Offshore Transmission System** and/or **Connection Site**. It is the case therefore that in cases where the **OTSUA** becomes operational prior to the **OTSUA Transfer Time** that a **EU Generator** is required to comply with this **ECC** 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 **ECC** shall be construed accordingly.

ECC.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 **ECC** to a relevant **Bilateral Agreement** includes the relevant **Construction Agreement**.

ECC.3 SCOPE

ECC.3.1 The **ECC** applies to **NGET** and to **EU Code Users**, which in the **ECC** means:

(a) **EU Generators** (other than those which only have **Embedded Small Power Stations**), including those undertaking **OTSDUW** including **Power Generating Modules,** and **DC Connected Power Park Modules** which satisfy the conditions specified in ECC.3.6

(b) **HVDC System Owners** which satisfy the conditions specified in ECC.3.6; and

(c) **BM Participants** and **Externally Interconnected System Operators** in respect of ECC.6.5 only.

(d) **Network Operators** only in respect of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** as provided for in ECC.3.2, ECC.3.3, EC3.4, EC3.5, ECC5.1, ECC.6.4.4 and ECA.3.4

(e) For the avoidance of doubt this **ECC** does not apply to **Network Operators** other than in respect of item ECC.3.1(f) above.

ECC.3.2 The above categories of **EU Code User** will become bound by the **ECC** 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.

ECC.3.3 **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded HVDC Systems** 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 HVDC Systems** not subject to a **Bilateral Agreement**.

ECC.3.3.1 The obligations within the **ECC** that are expressed to be applicable to **EU Generators** in respect of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **HVDC System Owners** in respect of **Embedded HVDC Systems** not subject to a **Bilateral Agreement** (where the obligations are in each case listed in ECC.3.3.2) shall be read and construed as obligations that the **Network Operator** within whose **System** any such **Medium Power Station** or **HVDC System** is **Embedded** must ensure are performed and discharged by the **EU Generator** or the **HVDC Owner**. **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded HVDC Systems** 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 HVDC System Owner** connected to an **Onshore User System Entry Point**.

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

ECC.5.1

ECC.5.2.2

ECC.5.3

ECC.6.1.3

ECC.6.1.5 (b)

ECC.6.3.2, ECC.6.3.3, ECC.6.3.4, ECC.6.3.6, ECC.6.3.7, ECC.6.3.8, ECC.6.3.9, ECC.6.3.10, ECC.6.3.12, ECC.6.3.13, ECC.6.3.15, ECC.6.3.16

ECC.6.4.4

ECC.6.5.6 (where required by ECC.6.4.4)

In respect of ECC.6.2.2.2, ECC.6.2.2.3, ECC.6.2.2.5, ECC.6.1.5(a), ECC.6.1.5(b) and ECC.6.3.11 equivalent provisions as co-ordinated and agreed with the **Network Operator** and **EU Generator** or **HVDC System Owner** may be required. Details of any such requirements will be notified to the **Network Operator** in accordance with ECC.3.5.

ECC.3.3.3 In the case of **Embedded Medium Power Station**s not subject to a **Bilateral Agreement** and **Embedded HVDC Systems** not subject to a **Bilateral Agreement** the requirements in:

ECC.6.1.6

ECC.6.3.8

ECC.6.3.12

ECC.6.3.15

ECC.6.3.16

ECC.6.3.17

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 **HVDC System** owner.

ECC.3.4 In the case of **Offshore Embedded Power Generating Modules** 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 Generating Modules** may be specified in the relevant **Bilateral Agreement** with the **Network Operator** or in any **Bilateral Agreement** between **NGET** and such **Offshore Generator**.

ECC.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 **EU Generator**. For the avoidance of doubt, requirements applicable to **EU 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**.

ECC.3.6 The requirements of this **ECC** shall apply to **EU Code Users** in respect of **Power Generating Modules** (including **DC Connected Power Park Modules**)and **HVDC Systems**

ECC.4 PROCEDURE

ECC.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 HVDC Systems**, becoming operational and includes provisions relating to certain conditions to be complied with by **EU Code Users** prior to and during the course of **NGET** notifying the **User** that it has the right to become operational. The procedure for an **EU Code User** to become connected is set out in the **Compliance Processes**.

ECC.5 CONNECTION

ECC.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 Stations** or **Embedded HVDC System**) 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 **European Connection Conditions** for that **EU Code 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 HVDC Systems** not subject to a **Bilateral Agreement**). References in the **ECC** 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.

ECC.5.2 Items For Submission

ECC.5.2.1 Prior to the **Completion Date** (or, where the **EU 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 ECC.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 ECC.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 ECC.7;

(l) a list of the telephone numbers for the **Users** facsimile machines referred to in ECC.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**.

ECC.5.2.2 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 ECC.6;

(c) the proposed name of the **Embedded Medium Power Station** or **Embedded HVDC System** (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**);

ECC.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 ECC.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**);

ECC.5.2.4 In the case of **OTSDUW Plant and Apparatus** (in addition to items under ECC.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 ECC.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 E1.

(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**);

5.3 (a) Of the items ECC.5.2.1 (c), (e), (g), (h), (k) and (m) need not be supplied in respect of **Embedded Power Stations** or **Embedded HVDC Systems**,

(b) item ECC.5.2.1(i) need not be supplied in respect of **Embedded Small Power Stations** and **Embedded Medium Power Stations** or **Embedded HVDC Systems** with a **Registered Capacity** of less than 100MW, and

(c) items ECC.5.2.1(d) and (j) are only needed in the case where the **Embedded Power Station** or the **Embedded HVDC System** is within a **Connection Site** with another **User**.

ECC.5.4 In addition, at the time the information is given under ECC.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**.

ECC.6 TECHNICAL, DESIGN AND OPERATIONAL CRITERIA

ECC.6.1 National Electricity Transmission System Performance Characteristics

ECC.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 ECC.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 ECC.6.1.5.

ECC.6.1.2 Grid Frequency Variations

ECC.6.1.2.1 Grid Frequency Variations for **EU Code User 's** excluding **HVDC Equipment**

ECC.6.1.2.1.1 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.

ECC.6.1.2.1.2 The **System Frequency** could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of **EU Code 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:

Frequency Range	Requirement
51.5Hz - 52Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz.
51Hz - 51.5Hz	Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz.
49.0Hz - 51Hz	Continuous operation is required
47.5Hz - 49.0Hz	Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz.
47Hz - 47.5Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz.

ECC.6.1.2.1.3 For the avoidance of doubt, disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz. **EU Generators** should however be aware of the combined voltage and frequency operating ranges as defined in ECC.6.3.12 and ECC.6.3.13.

ECC.6.1.2.1.4 **NGET** in co-ordination with the **Relevant Transmission Licensee** and/or **Network Operator** and a **User** may agree on wider variations in frequency or longer minimum operating times to those set out in ECC.6.1.2.1.2 or specific requirements for combined frequency and voltage deviations. Any such requirements in relation to **Power Generating Modules** shall be in accordance with ECC.6.3.12 and ECC.6.3.13. An **EU Code User** shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation taking account of their economic and technical feasibility.

ECC.6.1.2.2 Grid Frequency variations for **HVDC Systems** and **Remote End HVDC Converter Stations**

ECC.6.1.2.2.1 **HVDC Systems** and **Remote End HVDC Converter Stations** shall be capable of staying connected to the **System** and remaining operable within the frequency ranges and time periods specified in Table ECC.6.1.2.2 below. This requirement shall continue to apply during the **Fault Ride Through** conditions defined in ECC.6.3.15

Frequency Range (Hz)	Time Period for Operation (s)
47.0 – 47.5Hz	60 seconds
47.5 – 49.0Hz	90 minutes and 30 seconds
49.0 – 51.0Hz	Unlimited
51.0 – 51.5Hz	90 minutes and 30 seconds
51.5Hz – 52 Hz	20 minutes

Table ECC.6.1.2.2 – Minimum time periods **HVDC Systems** and **Remote End HVDC Converter Stations** shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the **National Electricity Transmission System**

ECC.6.1.2.2.2 **NGET** in coordination with the **Relevant Transmission Licensee** and a **HVDC System Owner** may agree wider frequency ranges or longer minimum operating times if required to preserve or restore system security. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the HV**DC System Owner** shall not unreasonably withhold consent.

ECC.6.1.2.2.3 Not withstanding the requirements of ECC.6.1.2.2.1, an **HVDC System** or **Remote End HVDC Converter Station** shall be capable of automatic disconnection at frequencies specified by **NGET** and/or **Relevant Network Operator**.

ECC.6.1.2.2.4 In the case of **Remote End HVDC Converter Stations** where the **Remote End HVDC Converter Station** is operating at either nominal frequency other than 50Hz or a variable frequency, the requirements defined in ECC6.1.2.2.1 to ECC.6.1.2.2.3 shall apply to the **Remote End HVDC Converter Station** other than in respect of the frequency ranges and time periods.

ECC.6.1.2.3 Grid Frequency Variations for **DC Connected Power Park Modules**

ECC.6.1.2.3.1 **DC Connected Power Park Modules** shall be capable of staying connected to the **Remote End DC Converter** network at the HVDC Interface Point and operating within the **Frequency** ranges and time periods specified in Table ECC.6.1.2.3 below. Where a nominal frequency other than 50Hz, or a **Frequency** variable by design is used as agreed with **NGET** and the **Relevant Transmission Licensee** the applicable **Frequency** ranges and time periods shall be specified in the **Bilateral Agreement** which shall (where applicable) reflect the requirements in Table ECC.6.1.2.3 .

Frequency Range (Hz)	Time Period for Operation (s)
47.0 – 47.5Hz	20 seconds
47.5 – 49.0Hz	90 minutes
49.0 – 51.0Hz	Unlimited
51.0 – 51.5Hz	90 minutes
51.5Hz – 52 Hz	15 minutes

Table ECC.6.1.2.3 – Minimum time periods a **DC Connected Power Park Module** shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the **System**

ECC.6.1.2.3.2 **NGET** in coordination with the **Relevant Transmission Licensee** and a **Generator** may agree wider frequency ranges or longer minimum operating times if required to preserve or restore system security and to ensure the optimum capability of the **DC Connected Power Park Module**. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the **EU Generator** shall not unreasonably withhold consent.

ECC.6.1.3 Not used

ECC.6.1.4 Grid Voltage Variations

ECC.6.1.4.1 Grid Voltage Variations for all **EU Code User's** excluding **DC Connected Power Park Modules** and **Remote End HVDC Converters**

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**, excluding **DC Connected Power Park Modules** and **Remote End HVDC Converters**) 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 Point** (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 110kV 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**), excluding **Connection Sites** for **DC Connected Power Park Modules** and **Remote End HVDC Converters**) will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, the 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:

National Electricity Transmission System Nominal Voltage	Normal Operating Range	Time period for Operation
400kV	400kV -10% to +5% 400kV +5% to +10%	Unlimited 15 minutes
275kV	275kV ±10%	Unlimited
132kV	132kV ±10%	Unlimited
110kV	110kV ±10%	Unlimited
Below 110kV	Below 110kV ±6%	Unlimited

NGET and a **EU Code User** may agree greater variations or longer minimum time periods of operation in voltage to those set out above in relation to a particular **Connection Site**, and insofar as a greater variation is agreed, the relevant figure set out above shall, in relation to that **EU Code User** at the particular **Connection Site**, be replaced by the figure agreed.

ECC.6.1.4.2 Grid Voltage Variations for all **DC Connected Power Park Modules**

ECC.6.1.4.2.1 All **DC Connected Power Park Modules** shall be capable of staying connected to the **Remote End HVDC Converter Station** at the **HVDC Interface Point** and operating within the voltage ranges and time periods specified in Tables ECC.6.1.4.2(a) and ECC.6.1.4.2(b) below. The applicable voltage range and time periods specified are selected based on the reference 1pu voltage.

Voltage Range (pu)	Time Period for Operation (s)
0.85pu – 0.9pu	60 minutes
0.9pu – 1.1pu	Unlimited
1.1pu – 1.15pu	15 minutes

Table ECC.6.1.4.2(a) – Minimum time periods for which **DC Connected Power Park Modules** shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is 110kV or above and less than 300kV.

Voltage Range (pu)	Time Period for Operation (s)
0.85pu – 0.9pu	60 minutes
0.9pu – 1.05pu	Unlimited
1.05pu – 1.15pu	15 minutes

Table ECC.6.1.4.2(b) – Minimum time periods for which **DC Connected Power Park Modules** shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is from 300kV up to and including 400kV.

ECC.6.1.4.2.2 **NGET** and a **EU Generator** in respect of a **DC Connected Power Park Module** may agree greater voltage ranges or longer minimum operating times. If greater voltage ranges or longer minimum times for operation are economically and technically feasible, the **EU Generator** shall not unreasonably withhold any agreement .

ECC.6.1.4.2.3 For **DC Connected Power Park Modules** which have an **HVDC Interface Point** to the **Remote End HVDC Converter Station**, **NGET** in coordination with the **Relevant Transmission Licensee** may specify voltage limits at the **HVDC Interface Point** at which the **DC Connected Power Park Module** is capable of automatic disconnection.

ECC.6.1.4.2.4 For **HVDC Interface Points** which fall outside the scope of ECC.6.1.4.2.1, ECC.6.1.4.2.2 and ECC.6.1.4.2.3, **NGET** in coordination with the **Relevant Transmission Licensee** shall specify any applicable requirements at the **Grid Entry Point** or **User System Entry Point**.

ECC.6.1.4.2.5 Where the nominal frequency of the AC collector **System** which is connected to an **HVDC Interface Point** is at a value other than 50Hz, the voltage ranges and time periods specified by **NGET** in coordination with the **Relevant Transmission Licensee** shall be proportional to the values specified in Table Table ECC.6.1.4.2(a) and Table ECC.6.1.4.2(b)

ECC.6.1.4.3 Grid Voltage Variations for all **Remote End HVDC Converters**

ECC.6.1.4.3.1 All **Remote End HVDC Converter Stations** shall be capable of staying connected to the **HVDC Interface Point** and operating within the voltage ranges and time periods specified in Tables ECC.6.1.4.3(a) and ECC.6.1.4.3(b) below. The applicable voltage range and time periods specified are selected based on the reference 1pu voltage.

Voltage Range (pu)	Time Period for Operation (s)
0.85pu – 0.9pu	60 minutes
0.9pu – 1.1pu	Unlimited
1.1pu – 1.15pu	15 minutes

Table ECC.6.1.4.3(a) – Minimum time periods for which a **Remote End HVDC Converter** shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is 110kV or above and less than 300kV.

Voltage Range (pu)	Time Period for Operation (s)
0.85pu – 0.9pu	60 minutes
0.9pu – 1.05pu	Unlimited
1.05pu – 1.15pu	15 minutes

Table ECC.6.1.4.3(b) – Minimum time periods for which **a Remote End HVDC Converter** shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is from 300kV up to and including 400kV.

ECC.6.1.4.3.2 **NGET** and a **HVDC System Owner** may agree greater voltage ranges or longer minimum operating times which shall be in accordance with the requirements of ECC.6.1.4.2.

ECC.6.1.4.3.4 For **HVDC Interface Points** which fall outside the scope of ECC.6.1.4.3.1 **NGET** in coordination with the **Relevant Transmission Licensee** shall specify any applicable requirements at the **Grid Entry Point** or **User System Entry Point**.

ECC.6.1.4.3.5 Where the nominal frequency of the AC collector **System** which is connected to an **HVDC Interface Point** is at a value other than 50Hz, the voltage ranges and time periods specified by **NGET** in coordination with the **Relevant Transmission Licensee** shall be proportional to the values specified in Table ECC.6.1.4.3(a) and Table ECC.6.1.4.3(b)

Voltage Waveform Quality

ECC.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 **User's** and **EU Code 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.

ECC.6.1.6 Across GB, under the **Planned Outage** conditions stated in ECC.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

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

1. The limits specified in Engineering Recommendation P28 Issue 2 as current at the Transfer Date ~~Table ECC.6.1.7 with the stated frequency of occurrence,~~ where:

~~(i)~~

$$\cancel{\%\Delta V_{steadystate} = \left| 100 \times \frac{\Delta V_{steadystate}}{V_0} \right|}$$

~~and~~

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$$\cancel{\%\Delta V_{max} = 100 \times \frac{\Delta V_{max}}{V_0}}$$ ~~;~~

~~(ii) V_0 is the initial steady state system voltage;~~

~~(iii) $V_{steadystate}$ 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 $\Delta V_{steadystate}$ is the absolute value of the difference between $V_{steadystate}$ and V_0;~~

~~(iv) ΔV_{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 dependent characteristic shown in Figure ECC.6.1.7;~~

(i~~viii~~) ~~—~~Voltage changes in C~~c~~ategory 3 ~~only occur infrequently, typically not planned more than once per year on average over the lifetime of a connection, and in circumstances~~ are typically 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

(ii~~x~~) For connections 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 C~~c~~ategory 2 or 3 to a lower number than specified in Table 4 of Engineering Recommendation P28 as current at the Transfer Date ~~ECC.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 4. ~~ECC.6.1.7.~~

~~Category~~	~~Maximum number of Occurrences~~	~~$\%\Delta V_{max}$ & $\%\Delta V_{steadystate}$~~
~~1~~	~~No Limit~~	~~$\lvert\%\Delta V_{max}\rvert \le 1\%$ & $\lvert\%\Delta V_{steadystate}\rvert \le 1\%$~~
~~2~~	~~$\frac{3600}{\sqrt[0.304]{2.5 \times \%\Delta V_{max}}}$ occurrences per hour with events evenly distributed~~	~~$1\% < \lvert\%\Delta V_{max}\rvert \le 3\%$ & $\lvert\%\Delta V_{steadystate}\rvert \le 3\%$~~

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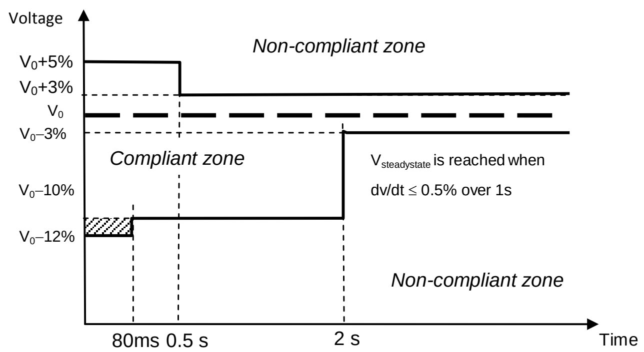
~~3~~	~~No more than 4 per day for Commissioning, Maintenance and Fault Restoration~~	~~For decreases in voltage:~~ ~~$\%\Delta V_{max} \leq 12\%$[1] &~~ ~~$\%\Delta V_{steadystate} \leq 3\%$~~ ~~For increases in voltage:~~ ~~$\%\Delta V_{max} \leq 5\%$[2] &~~ ~~$\%\Delta V_{steadystate} \leq 3\%$~~ ~~(see Figure ECC6.1.7)~~

~~Table ECC.6.1.7 – Limits for Rapid Voltage Changes~~

~~[1] A decrease in voltage of up to 12% is permissible for up to 80ms, as highlighted in the shaded area in Figure ECC.6.1.7, reducing to up to 10% after 80ms and to up to 3% after 2 seconds.~~

~~[2] An increase in voltage of up to 5% is permissible if it is reduced to up to 3% after 0.5 seconds.~~



~~Figure ECC.6.1.7 –~~

~~Time and magnitude limits for a category 3 Rapid Voltage Change~~

(b) ~~For voltages above 132kV,~~ The limits for **Flicker Severity (Short Term)** ~~of 0.8 Unit~~ and ~~a~~ **Flicker Severity (Long Term)** ~~of 0.6 Unit, for voltages 132kV and below, **Flicker Severity (Short Term)** of 1.0 Unit and a **Flicker Severity (Long Term)**) of 0.8 Unit,~~ as set out in **Engineering Recommendation** P28 as current at the **Transfer Date**.

ECC.6.1.8 Voltage fluctuations at a **Point of Common Coupling** 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 (SSTI)

ECC.6.1.9 **NGET** shall ensure that **Users' Plant and Apparatus** will not be subject to unacceptable Sub-Synchronous Oscillation conditions as specified in the relevant **License Standards**.

ECC.6.1.10 **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**.

ECC.6.2 Plant and Apparatus relating to Connection Sites and Interface Points and HVDC Interface Points

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**), **HVDC Interface Point**s relating to **Remote End HVDC Converters** and **Connection Points** which (except as otherwise provided in the relevant paragraph) each **EU Code User** must ensure are complied with in relation to its **Plant** and **Apparatus** and which in the case of ECC.6.2.2.2.2, ECC.6.2.3.1.1 and ECC.6.2.1.1(b) only, **NGET** must ensure are complied with in relation to **Transmission Plant** and **Apparatus**, as provided in those paragraphs.

ECC.6.2.1 General Requirements

6.2.1.1 (a) The design of connections between the **National Electricity Transmission System** and:

(i) any **Power Generating Module Generating Unit** (other than a **CCGT Unit** or **Power Park Unit**) **HVDC Equipment**, **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 **EU Code User**.

ECC.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~~i~~) **Plant** and/or **Apparatus** in respect of **EU Code User's** connecting to 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** or **Remote End HVDC Converter Station** at the **HVDC Interface Point**) 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**.

(ii~~i~~) <u>**EU Code User's Plant** and/or **Apparatus** connecting to an existing **Connection Point** (including **OTSDUW Plant** and **Apparatus** at the **Interface Point**)</u>

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** or **Remote End HVDC Converter Stations** at the **HVDC Interface Point**)-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) <u>Used Plant and/or Apparatus being moved, re-used or modified</u>

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) or (ii) 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 ECC.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 **EU Code User** . **NGET** shall also provide a copy of the list to any **EU Code User** upon receipt of an application form for a **Bilateral Agreement** for a new **Connection Point**.

(c) Where the **EU Code User** provides **NGET** with information and/or test reports in respect of **Plant** and/or **Apparatus** which the **EU Code 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.

ECC.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**

ECC.6.2.2.1 Not Used.

ECC.6.2.2.2 **Power Generating Module**, **OTSDUW Plant and Apparatus, HVDC Equipment** and **Power Station** Protection Arrangements

ECC.6.2.2.2.1 Minimum Requirements

Protection of **Power Generating Modules** (other than **Power Park Units**), **HVDC Equipment**, **OTSDUW Plant and Apparatus** 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** (including **DC Connected Power Park Modules**) or **HVDC System Owners**.

ECC.6.2.2.2.2 Fault Clearance Times

(a) The required fault clearance time for faults on the **Generator's** (including **DC Connected Power Park Modules**) or **HVDC System 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 **EU Generator** (including **DC Connected Power Park Modules**) or **HVDC System 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 **Relevant Transmission Licensee** or the **EU Generator** (including in respect of **OTSDUW Plant and Apparatus** and **DC Connected Power Park Modules**) 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 **EU Generator** or **HVDC System 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 **HVDC System 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 **Power Generating Module** (other than a **Power Park Unit**), **HVDC Equipment** or **OTSDUW Plant and Apparatus** 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 **EU Generators** (including in respect of **OTSDUW Plant and Apparatus** and **DC Connected Power Park Modules**) and **HVDC System Owners** 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 **Power Generating Module** (other than a **Power Park Unit**), **HVDC Equipment** or **OTSDUW Plant and Apparatus** 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 **DC Connected Power Park Modules**) and the **HVDC System 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**.

A Power Generating Module (other than a **Power Park Unit**), **HVDC Equipment** 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 **EU Generator** (including in the case of **OTSDUW Plant and Apparatus** or **DC Connected Power Park Module**) or **HVDC System** is connected at 132kV and below. This will permit **Discrimination** between the **Generator** in respect of **OTSDUW Plant** and **Apparatus** or **DC Connected Power Park Modules** or **HVDC System 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 **Power Generating Module** (other than **Power Park Units**), or the **HVDC Equipment** 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 **DC Connected Power Park Modules**) or the **HVDC System** owner, or **NGET**, as the case may be, to interrupt fault current interchange with the **National Electricity Transmission System**, or **Generator's System**, or **HVDC System 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 Connected Power Park Modules**) or **HVDC System-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**.

ECC.6.2.2.3 Equipment including **Protection** equipment to be provided

NGET shall specify the **Protection** schemes and settings necessary to protect the **National Electricity Transmission System**, taking into account the characteristics of the **Power Generating Module** or **HVDC Equipment**.

The protection schemes needed for the **Power Generating Module** or **HVDC Equipment** and the **National Electricity Transmission System** as well as the settings relevant to the **Power Generating Module** and/or **HVDC Equipment** shall be coordinated and agreed between **NGET** and the **EU Generator** or **HVDC System Owner.** The agreed **Protection** schemes and settings will be specified in the **Bilateral Agreement**.

The protection schemes and settings for internal electrical faults must not prevent the **Power Generating Module** or **HVDC Equipment** from satisfying the requirements of the Grid Code although **EU Generators** should be aware of the requirements of ECC.6.3.13.1. ;

~~electrical~~ **Protection** of the **Power Generating Module** or **HVDC Equipment** shall take precedence over operational controls, taking into account the security of the **National Electricity Transmission System** and the health and safety of personnel, as well as mitigating any damage to the **Power Generating Module** or **HVDC Equipment**.

ECC.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 E**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**.

ECC.6.2.2.3.2 Circuit-breaker fail Protection

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

ECC.6.2.2.3.3 Loss of Excitation

The **EU Generator** must provide **Protection** to detect loss of excitation in respect of each of its **Generating Units** within a **Synchronous Power Generating Module** to initiate a **Generating Unit** trip.

ECC.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 **EU Generators** to fit pole-slipping **Protection** on their **Generating Units** within each **Synchronous Power Generating Module**.

ECC.6.2.2.3.5 Signals for Tariff Metering

EU Generators and **HVDC System 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**.

ECC.6.2.2.3.6 Commissioning of Protection Systems

No **EU Generator** or **HVDC System Owner** equipment shall be energised until the **Protection** settings have been finalised. The **EU Generator** or **HVDC System Owner** shall agree with **NGET** (in coordination with the **Relevant Transmission Licensee**) and carry out a combined commissioning programme for the **Protection** systems, and generally, to a minimum standard as specified in the **Bilateral Agreement**.

ECC.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 **Power Generating Module**, **HVDC Equipment** itself) may be worked upon or altered by the **EU Generator** or **HVDC System 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**.

ECC.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**.

ECC.6.2.2.6 Changes to **Protection** Schemes and **HVDC System** Control Modes

ECC.6.2.2.6.1 Any subsequent alterations to the protection settings (whether by **NGET**, the **Relevant Transmission Licensee**, the **EU Generator** or the **HVDC System Owner**) shall be agreed between **NGET** (in co-ordination with the **Relevant Transmission Licensee**) and the **EU Generator** or **HVDC System Owner** in accordance with the Grid Code (ECC.6.2.2.5). No alterations are to be made to any protection schemes unless agreement has been reached between **NGET**, the **Relevant Transmission Licensee**, the **EU Generator** or **HVDC System Owner**.

ECC.6.2.2.6.2 The parameters of different control modes of the **HVDC System** shall be able to be changed in the **HVDC Converter Station**, if required by **NGET** in coordination with the **Relevant Transmission Licensee** and in accordance with ECC.6.2.2.6.4.

ECC.6.2.2.6.3 Any change to the schemes or settings of parameters of the different control modes and protection of the **HVDC System** including the procedure shall be agreed with **NGET** in coordination with the **Relevant Transmission Licensee** and the **HVDC System Owner**.

ECC.6.2.2.6.4 The control modes and associated set points shall be capable of being changed remotely, as specified by **NGET** in coordination with the **Relevant Transmission Licensee**.

ECC.6.2.2.7 Control Schemes and Settings

ECC.6.2.2.7.1 The schemes and settings of the different control devices on the **Power Generating Module** and **HVDC Equipment** that are necessary for **Transmission System** stability and for taking emergency action shall be agreed with **NGET** in coordination with the **Relevant Transmission Licensee** and the **EU Generator** or **HVDC System Owner**.

ECC.6.2.2.7.2 Subject to the requirements of ECC.6.2.2.7.1 any changes to the schemes and settings, defined in ECC.6.2.2.7.1, of the different control devices of the **Power Generating Module** or **HVDC Equipment** shall be coordinated and agreed between **NGET**, the **Relevant Transmission Licensee,** the **EU Generator** and **HVDC System Owner**.

ECC.6.2.2.8 Ranking of **Protection** and Control

ECC.6.2.2.8.1 **NGET** in coordination with **Relevant Transmission Licensees**, shall agree and coordinate the protection and control devices of **EU Generators Plant** and **Apparatus** in accordance with the following general priority ranking (from highest to lowest):

1. The interface between the **National Electricity Transmission System** and the **Power Generating Module** or **HVDC Equipment Protection** equipment;
2. frequency control (active power adjustment);
3. power restriction; and
4. power gradient constraint;

ECC.6.2.2.8.2 A control scheme, specified by the **HVDC System Owner** consisting of different control modes, including the settings of the specific parameters, shall be coordinated and agreed between **NGET** in coordination with the **Relevant Transmission Licensee** and the **HVDC System Owner**. These details would be specified in the **Bilateral Agreement**.

ECC.6.2.2.8.3 **NGET** in coordination with **Relevant Transmission Licensees**, shall agree and coordinate the protection and control devices of **HVDC System Owners Plant** and **Apparatus** in accordance with the following general priority ranking (from highest to lowest)

1. The interface between the **National Electricity Transmission System** and **HVDC System Protection** equipment;
2. **Active Power** control for emergency assistance
3. automatic remedial actions as specified in ECC.6.3.6.1.2.5
4. **Limited Frequency Sensitive Mode** (LFSM) of operation;
5. **Frequency Sensitive Mode** of operation and **Frequency** control; and
6. power gradient constraint.

ECC.6.2.2.9 Synchronising

ECC.6.2.2.9.1 For any **Power Generating Module** directly connected to the **National Electricity Transmission System** or **Type D Power Generating Module**, synchronisation shall be performed by the **EU Generator** only after instruction by **NGET** in accordance with the requirements of BC.2.5.2.

ECC.6.2.2.9.2 Each **Power Generating Module** directly connected to the **National Electricity Transmission System** or **Type D Power Generating Module** shall be equipped with the necessary synchronisation facilities. Synchronisation shall be possible within the range of frequencies specified in ECC.6.1.2.

ECC.6.2.2.9.3 The requirements for synchronising equipment shall be specified in accordance with the requirements in the **Electrical Standards** listed in the annex to the **General Conditions**. The synchronisation settings shall include the following elements below. Any variation to these requirements shall be pursuant to the terms of the **Bilateral Agreement**.

1. voltage

2. Frequency

3. phase angle range

4. phase sequence

5. deviation of voltage and **Frequency**

ECC.6.2.2.9.4 **HVDC Equipment** shall be required to satisfy the requirements of ECC.6.2.2.9.1 – ECC.6.2.2.9.3. In addition, unless otherwise specified by **NGET**, during the synchronisation of a **DC Connected Power Park Module** to the **National Electricity Transmission System**, any **HVDC Equipment** shall have the capability to limit any steady state voltage changes to the limits specified within ECC.6.1.7 or ECC.6.1.8 (as applicable) which shall not exceed 5% of the pre-synchronisation voltage. **NGET** in coordination with the **Relevant Transmission Licensee** shall specify any additional requirements for the maximum magnitude, duration and measurement of the voltage transients over and above those defined in ECC.6.1.7 and ECC.6.1.8 in the **Bilateral Agreement**.

ECC.6.2.2.9.5 **EU Generators** in respect of **DC Connected Power Park Modules** shall also provide output synchronisation signals specified by **NGET** in co-ordination with the **Relevant Transmission Licensee**.

ECC.6.2.2.9.6 In addition to the requirements of ECC.6.2.2.9.1 to ECC.6.2.2.9.5, **EU Generators** and **HVDC System Owners** should also be aware of the requirements of ECC.6.5.10 relating to busbar voltage

ECC.6.2.2.9.10 <u>HVDC Parameters and Settings</u>

ECC.6.2.2.9.10.1 The parameters and settings of the main control functions of an **HVDC System** shall be agreed between the **HVDC System** owner and **NGET** , in coordination with the **Relevant Transmission Licensee**. The parameters and settings shall be implemented within such a control hierarchy that makes their modification possible if necessary. Those main control functions are at least:

(b) **Frequency Sensitive Modes** (FSM, LFSM-O, LFSM-U);

(c) **Frequency** control, if applicable;

(d) **Reactive Power** control mode, if applicable;

(e) power oscillation damping capability;

(f) subsynchronous torsional interaction damping capability,.

ECC.6.2.2.11 <u>Automatic Reconnection</u>

ECC.6.2.2.11.1 **EU Generators** in respect of **Type A**, **Type B**, **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) which have signed a **CUSC Contract** with **NGET** are not permitted to automatically reconnect to the **Total System** without instruction from **NGET**. **NGET** will issue instructions for re-connection or re-synchronisation in accordance with the requirements of BC2.5.2. Where synchronising is permitted in accordance with BC2.5.2, the voltage and frequency at the **Grid Entry Point** or **User System Entry Point** shall be within the limits defined in ECC.6.1.2 and ECC.6.1.4 and the ramp rate limits pursuant to BC1.A.1.1. For the avoidance of doubt this requirement does not apply to **EU Generators** who are not required to satisfy the requirements of the Balancing Codes.

ECC.6.2.2.12 <u>Automatic Disconnection</u>

ECC.6.2.2.12.1 No **Power Generating Module** or **HVDC Equipment** shall disconnect within the frequency range or voltage range defined in ECC.6.1.2 and ECC.6.1.4.

ECC.6.2.2.13 <u>Special Provisions relating to Power Generating Modules embedded within Industrial Sites which supply electricity as a bi-product of their industrial process</u>

ECC.6.2.2.13.1 **Generators** in respect of **Power Generating Modules** which form part of an industrial network, where the **Power Generating Module** is used to supply critical loads within the industrial process shall be permitted to operate isolated from the **Total System** if agreed with **NGET** in the **Bilateral Agreement**.

ECC.6.2.2.13.2 Except for the requirements of ECC.6.3.3 and ECC.6.3.7.1, **Power Generating Modules** which are embedded within industrial sites are not required to satisfy the requirements of ECC.6.3.6.2.1 and ECC.6.3.9. In this case this exception would only apply to **Power Generating Modules** on industrial sites used for combined heat and power production which are embedded in the network of an industrial site where all the following criteria are met.

1. The primary purpose of these sites is to produce heat for production processes of the industrial site concerned,
2. Heat and power generation is inextricably interlinked, that is to say any change to heat generation results inadvertently in a change of active power generating and visa versa.
3. The **Power Generating Modules** are of **Type A**, **Type B** or **Type C**.
4. Combined heat and power generating facilities shall be assessed on the basis of their electrical **Maximum Capacity**.

ECC.6.2.3 <u>Requirements at **Connection Points** relating to **Network Operators** and **Non-Embedded Customers**</u>

ECC.6.2.3.1 <u>Protection Arrangements for **EU Code User's** in respect of **Network Operators** and **Non-Embedded Customers**</u>

ECC.6.2.3.1.1 **Protection** arrangements for **EU Code User's** in respect of **Network Operators** and **Non-Embedded Customers User Systems** directly connected to the **National Electricity Transmission System**, shall meet the requirements given below:

<u>Fault Clearance Times</u>

(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** or **Relevant Transmission Licensee** 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 ECC.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**.

ECC.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**.

ECC.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**.

ECC.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**.

ECC.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**.

ECC.6.2.3.6 Equipment including **Protection** equipment to be provided

NGET in coordination with the **Relevant Transmission Licensee** shall specify and agree the **Protection** schemes and settings required to protect the **National Electricity Transmission System** in accordance with the characteristics of the **Network Operators** or **Non Embedded Customers System**. **NGET** in coordination with the **Relevant Transmission Licensee** and the **Network Operator** or **Non Embedded Customer** shall agree on the protection schemes and settings in respect of the busbar protection zone in respect of each **Grid Supply Point**.

Protection of the **Network Operators** or **Non Embedded Customers System** shall take precedence over operational controls whilst respecting the security of the **National Electricity Transmission System** and the health and safety of staff and the public.

ECC.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**.

ECC.6.2.3.7 Changes to **Protection** Schemes

Any subsequent alterations to the busbar protection settings (whether by **NGET**, the **Relevant Transmission Licensee**, the **Network Operator** or the **Non Embedded Customer**) shall be agreed between **NGET** (in co-ordination with the **Relevant Transmission Licensee**) and the **Network Operator** or **Non Embedded Customer** in accordance with the Grid Code (ECC.6.2.3.4). No alterations are to be made to any busbar protection schemes unless agreement has been reached between **NGET**, the **Relevant Transmission Licensee**, the **Network Operator** or **Non Embedded Customer**.

No **Network Operator** or **Non Embedded Customer** equipment shall be energised until the **Protection** settings have been finalised. The **Network Operator** or **Non Embedded Customer** shall agree with **NGET** (in coordination with the **Relevant Transmission Licensee**) and carry out a combined commissioning programme for the **Protection** systems, and generally, to a minimum standard as specified in the **Bilateral Agreement**.

ECC.6.2.3.8 Control Requirements

ECC.6.2.3.8.1 **NGET** in coordination with the **Relevant Transmission Licensee** and the **Network Operator** or **Non Embedded Customer** shall agree on the control schemes and settings of the different control devices of the **Network Operators** or **Non Embedded Customers System** relevant for security of the **National Electricity Transmission System**. Such requirements would be pursuant to the terms of the **Bilateral Agreement** which shall also cover at least the following elements:

1. Isolated (**National Electricity Transmission System**) operation
2. Damping of oscillations
3. Disturbances to the **National Electricity Transmission System**
4. Automatic switching to emergency supply and restoration to normal topology
5. Automatic circuit breaker re-closure (on 1-phase faults)

ECC.6.2.3.8.2 Subject to the requirements of ECC.6.2.3.8.1 any changes to the schemes and settings, defined in ECC.6.2.3.8.1 of the different control devices of the **Network Operators** or **Non-Embedded Customers System** at the **Grid Supply Point** shall be coordinated and agreed between **NGET**, the **Relevant Transmission Licensee**, the **Network Operator** or **Non Embedded Customer**.

ECC.6.2.3.9 Ranking of **Protection** and Control

ECC.6.2.3.9.1 The **Network Operator** or the **Non Embedded Customer** shall set the **Protection** and control devices of its **System** , in compliance with the following priority ranking, organised in decreasing order of importance:

(a) **National Electricity Transmission System Protection**;

(b) **Protection** equipment at each **Grid Supply Point**;

(c) **Frequency** control (**Active Power** adjustment);

(d) **P**ower restriction.

ECC.6.2.3.10 Synchronising

ECC.6.2.3.10.1 Each **Network Operator** or **Non Embedded Customer** directly connected to the **National Electricity Transmission System** shall be capable of synchronisation within the range of frequencies specified in ECC.6.1.2.

ECC.6.2.3.10.2 **NGET** and the **Network Operator** or **Non Embedded Customer** shall agree on the settings of the synchronisation equipment prior to the **Completion Date**. The synchronisation settings shall include the following elements which shall be pursuant to the terms of the **Bilateral Agreement**.

1. voltage

2. Frequency

3. phase angle range

4. deviation of voltage and **Frequency**

ECC.6.3 GENERAL POWER GENERATING MODULE, OTSDUW AND HVDC EQUIPMENT REQUIREMENTS

ECC.6.3.1 This section sets out the technical and design criteria and performance requirements for **Power Generating Modules** and **HVDC Equipment** (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 **HVDC System Owner** must ensure are complied with in relation to its **Power Generating Modules**, **HVDC Equipment** and **OTSDUW Plant and Apparatus** . References to **Power Generating Modules**, **HVDC Equipment** in this ECC.6.3 should be read accordingly.

Plant Performance Requirements

ECC.6.3.2 REACTIVE CAPABILITY

ECC.6.3.2.1 Reactive Capability for **Type B Synchronous Power Generating Modules**

ECC.6.3.2.1.1 When operating at **Maximum Capacity**, all **Type B Synchronous Power Generating Modules** must be capable of continuous operation at any points between the limits of 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Grid Entry Point** or **User System Entry Point** unless otherwise agreed with **NGET** or relevant **Network Operator**. At **Active Power** output levels other than **Maximum Capacity**, all **Generating Units** within a **Type B Synchronous Power Generating Module** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the **HV Generator Performance Chart** unless otherwise agreed with **NGET** or relevant **Network Operator**.

ECC.6.3.2.2 Reactive Capability for **Type B Power Park Modules**

ECC.6.3.2.2.1 When operating at **Maximum Capacity** all **Type B Power Park Modules** must be capable of continuous operation at any points between the limits of 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Grid Entry Point** or **User System Entry Point** unless otherwise agreed with **NGET** or relevant **Network Operator**. At **Active Power** output levels other than **Maximum Capacity**, each **Power Park Module** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the **HV Generator Performance Chart** unless otherwise agreed with **NGET** or **Network Operator**.

ECC.6.3.2.3 Reactive Capability for **Type C** and **D Synchronous Power Generating Modules**

ECC.6.3.2.3.1 In addition to meeting the requirements of ECC.6.3.2.3.2 – ECC.6.3.2.3.5, **EU Generators** which connect a **Type C** or **Type D Synchronous Power Generating Module**(s) to a **Non Embedded Customers System** or private network, may be required to meet additional reactive compensation requirements at the point of connection between the **System** and the **Non Embedded Customer** or private network where this is required for **System** reasons.

ECC.6.3.2.3.2 All **Type C** and **Type D Synchronous Power Generating Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Grid Entry Point** or **User System Entry Point** as defined in Figure ECC.6.3.2.3 when operating at **Maximum Capacity**.

ECC.6.3.2.3.3 At **Active Power** output levels other than **Maximum Capacity**, all **Generating Units** within a **Synchronous Power Generating Module** must be capable of continuous operation at any point between the **Reactive Power** capability limit identified on the **HV Generator Performance Chart** at least down to the **Minimum Stable Operating Level**. At reduced **Active Power** output, **Reactive Power** supplied at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) shall correspond to the **HV Generator Performance Chart** of the **Synchronous Power Generating Module**, taking the auxiliary supplies and the **Active Power** and **Reactive Power** losses of the **Generating Unit** transformer or **Station Transformer** into account.

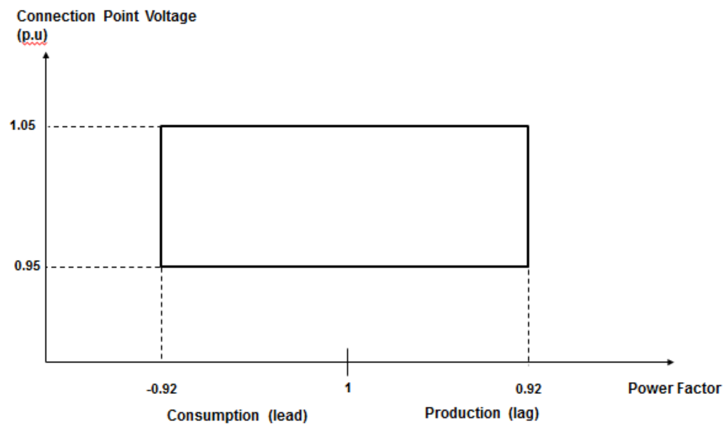


Figure ECC.6.3.2.3

ECC.6.3.2.3.4 In addition, to the requirements of ECC.6.3.2.3.1 – ECC.6.3.2.3.3 the short circuit ratio of all **Onshore Synchronous Generating Units** with an **Apparent Power** rating of less than 1600MVA shall not be 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.

ECC.6.3.2.4 <u>Reactive Capability for **Type C** and **D Power Park Modules**, **HVDC Equipment** and **OTSDUW Plant and Apparatus** at the **Interface Point**</u>

ECC.6.3.2.4.1 **EU Generators** or **HVDC System Owners** which connect an **Onshore Type C** or **Onshore Type D Power Park Module** or **HVDC Equipment** to a **Non Embedded Customers System** or private network, may be required to meet additional reactive compensation requirements at the point of connection between the **System** and the **Non Embedded Customer** or private network where this is required for **System** reasons.

ECC.6.3.2.4.2 All **Onshore Type C Power Park Modules** and **Onshore Type D Power Park Modules** or **HVDC Converters** at an **HVDC Converter Station** with a **Grid Entry Point** or **User System Entry Point** voltage above 33kV, or **Remote End HVDC Converters** with an **HVDC Interface Point** voltage above 33kV, or **OTSDUW Plant and Apparatus** with an **Interface Point** voltage above 33kV shall be capable of satisfying the **Reactive Power** capability requirements at the **Grid Entry Point** or **User System Entry Point** (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**, or **HVDC Interface Point** in the case of a **Remote End HVDC Converter Station**) as defined in Figure ECC.6.3.2.4(a) when operating at **Maximum Capacity** (or **Interface Point Capacity** in the case of **OTSUW Plant and Apparatus**). In the case of **Remote End HVDC Converters** and **DC Connected Power Park Modules**, **NGET** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for **Offshore Power Park Modules** and **DC Connected Power Park Modules** are defined in ECC.6.3.2.5 and ECC.6.3.2.6.

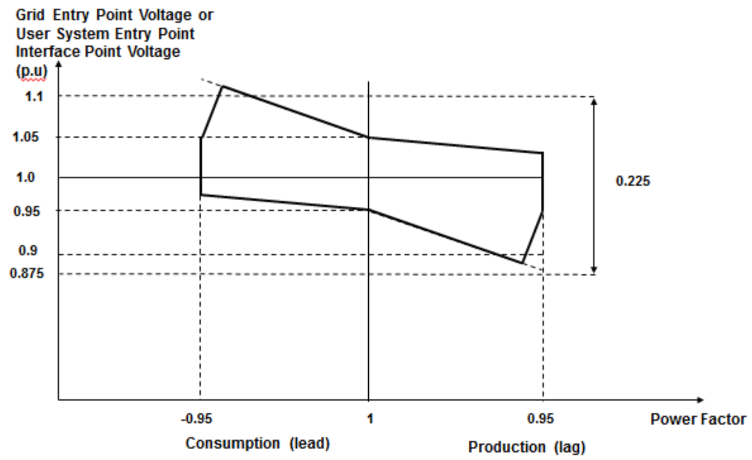


Figure ECC.6.3.2.4(a)

ECC.6.3.2.4.3 All **Onshore Type C** or **Type D Power Park Modules** or **HVDC Converters** at a **HVDC Converter Station** with a **Grid Entry Point** or **User System Entry Point** voltage at or below 33kV or **Remote End HVDC Converter Station** with an **HVDC Interface Point Voltage** at or below 33kV shall be capable of satisfying the **Reactive Power** capability requirements at the **Grid Entry Point** or **User System Entry Point** as defined in Figure ECC.6.3.2.4(b) when operating at **Maximum Capacity**. In the case **of Remote End HVDC Converters NGET** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(b), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for **Offshore Power Park Modules** and **DC Connected Power Park Modules** are defined in ECC.6.3.2.5 and ECC.6.3.2.6.

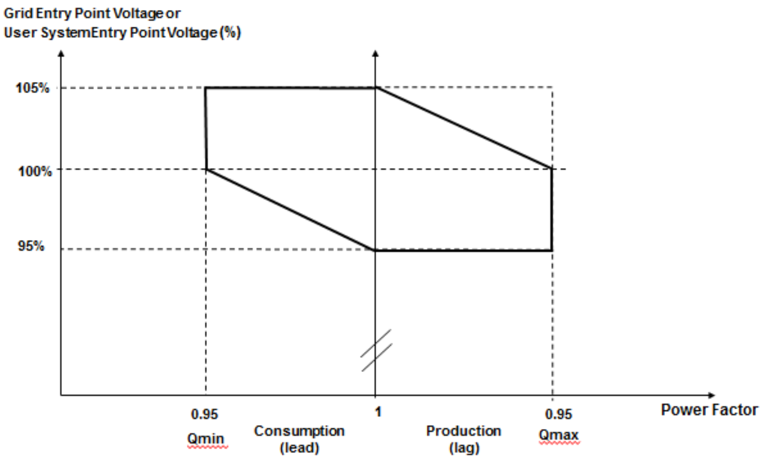


Figure ECC.6.3.2.4(a)

ECC.6.3.2.4.4 All **Type C** and **Type D Power Park Modules**, **HVDC Converters** at a **HVDC Converter Station** including **Remote End HVDC Converters** or **OTSDUW Plant and Apparatus**, shall be capable of satisfying the **Reactive Power** capability requirements at the **Grid Entry Point** or **User System Entry Point** (or **Interface Point Capacity** in the case of **OTSUW Plant and Apparatus** or **HVDC Interface Point** in the case of **Remote End HVDC Converter Stations**) as defined in Figure ECC.6.3.2.4(c) when operating below **Maximum Capacity**. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure ECC.6.3.2.4(c) unless the requirement to maintain the **Reactive Power** limits defined at **Maximum Capacity** (or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**) under absorbing **Reactive Power** conditions down to 20% **Active Power** output has been specified by **NGET**. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service. In the case of **Remote End HVDC Converters**, **NGET** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for **Offshore Power Park Modules** and **DC Connected Power Park Modules** are defined in ECC.6.3.2.5 and ECC.6.3.2.6.

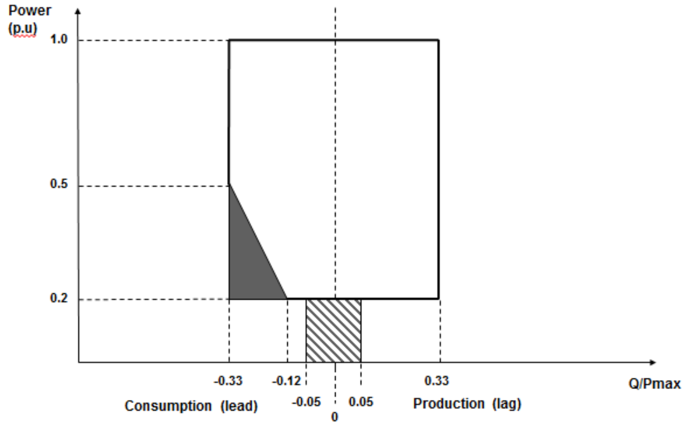


Figure ECC.6.3.2.4(c)

ECC.6.3.2.5 <u>Reactive Capability for **Offshore Synchronous Power Generating Modules**, **Configuration 1 AC connected Offshore Power Park Modules** and **Configuration 1 DC Connected Power Park Modules.**</u>

ECC.6.3.2.5.1 The short circuit ratio of any **Offshore Synchronous Generating Units** within a **Synchronous Power Generating Module** shall not be less than 0.5. All **Offshore Synchronous Generating Units, Configuration 1 AC connected Offshore Power Park Modules** or **Configuration 1 DC Connected Power Park Modules** must be capable of maintaining zero transfer of **Reactive Power** at the **Offshore Grid Entry Point**. 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 **Maximum Capacity**.

ECC.6.3.2.5.2 For the avoidance of doubt if an **EU Generator** (including those in respect of **DC Connected Power Park Modules**) wishes to provide a **Reactive Power** capability in excess of the minimum requirements defined in ECC.6.3.2.5.1 then such capability (including steady state tolerance) shall be agreed between the **Generator**, **Offshore Transmission Licensee** and **NGET** and/or the relevant **Network Operator.**

ECC.6.3.2.6 <u>Reactive Capability for **Configuration 2 AC Connected Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules**.</u>

ECC.6.3.2.6.1 All **Configuration 2 AC connected Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules** shall be capable of satisfying the minimum **Reactive Power** capability requirements at the **Offshore Grid Entry Point** as defined in Figure ECC.6.3.2.6(a) when operating at **Maximum Capacity**. **NGET** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.6(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies.

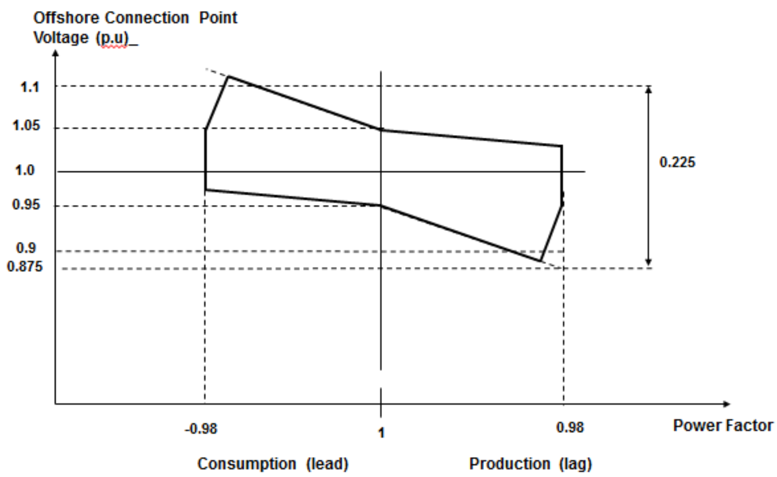


Figure ECC.6.3.2.6(a)

ECC.6.3.2.6.2 All **AC Connected Configuration 2 Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Offshore Grid Entry Point** as defined in Figure ECC.6.3.2.6(b) when operating below **Maximum Capacity**. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure ECC.6.3.2.6(b) unless the requirement to maintain the **Reactive Power** limits defined at **Maximum Capacity** (or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**) under absorbing **Reactive Power** conditions down to 20% **Active Power** output has been specified with **NGET**. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service. **NGET** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.6(b), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies.

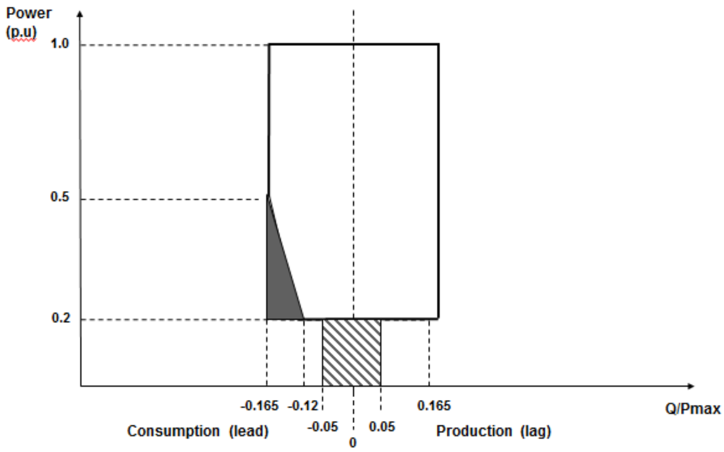


Figure ECC.6.3.2.6(b)

ECC.6.3.2.6.3 For the avoidance of doubt if an **EU Generator** (including **Generators** in respect of **DC Connected Power Park Modules** referred to in ECC.6.3.2.6.2) wishes to provide a **Reactive Power** capability in excess of the minimum requirements defined in ECC.6.3.2.6.1 then such capability (including any steady state tolerance) shall be between the **EU Generator**, **Offshore Transmission Licensee** and **NGET** and/or the relevant **Network Operator**.

ECC.6.3.3 <u>OUTPUT POWER WITH FALLING FREQUENCY</u>

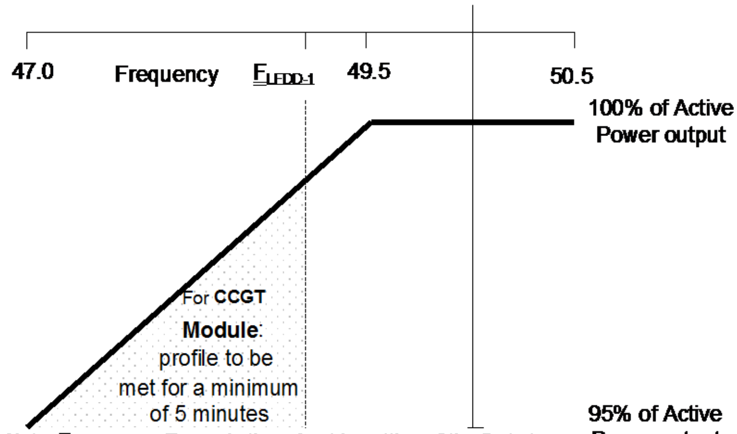
ECC.6.3.3.1 <u>Output power with falling frequency for **Power Generating Modules** and **HVDC Equipment**</u>

CC.6.3.3.1.1 Each **Power Generating Module** and **HVDC Equipment** 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 ECC.6.1.2) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure ECC.6.3.3(a) for **System Frequency** changes within the range 49.5 to 47 Hz for all ambient temperatures up to and including 25^{0}C, 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**. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure ECC.6.3.3(a) these measures should be still continued at ambient temperatures above 25^{0}C maintaining as much of the **Active Power** achievable within the capability of the plant.

Figure ECC.6.3.3(a)



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

(d) An **HVDC System** 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 HVDC System**) at a level not greater than the figure determined by the linear relationship shown in Figure ECC.6.3.3(b) for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47.8 Hz the **Active Power** input decreases by more than 60%.

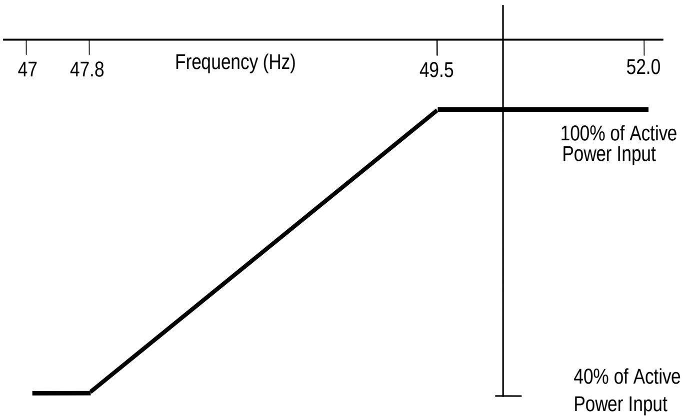


Figure ECC.6.3.3(b)

(e) In the case of an **Offshore Generating Unit** or **Offshore Power Park Module** or **DC Connected Power Park Module** or **Remote End HVDC Converter** or **Transmission DC Converter**, the **EU Generator** shall comply with the requirements of ECC.6.3.3. **EU 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 **EU Generators** to fulfil their obligations.

(f) **Transmission DC Converters** and **Remote End HVDC Converters** shall provide a continuous signal indicating the real time frequency measured at the **Interface Point** to the **Offshore Grid Entry Point** or **HVDC Interface Point** for the purpose of **Offshore Generators** or **DC Connected Power Park Modules** to respond to changes in **System Frequency** on the Main Interconnected **Transmission System**. A **DC Connected Power Park Module** or **Offshore Power Generating Module** shall be capable of receiving and processing this signal within 100ms.

ECC.6.3.4 ACTIVE POWER OUTPUT UNDER SYSTEM VOLTAGE VARIATIONS

ECC.6.3.4.1 At the **Grid Entry Point** or **User System Entry Point** , the **Active Power** output under steady state conditions of any **Power Generating Module** or **HVDC Equipment** 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 ECC.6.1.4 by more than the change in **Active Power** losses at reduced or increased voltage.

ECC.6.3.5 BLACK START

ECC.6.3.5.1 **Black Start** is not a mandatory requirement, however **EU Code Users** may wish to notify **NGET** of their ability to provide a **Black Start** facility and the cost of the service. **NGET** will then consider whether it wishes to contract with the **EU Code User** for the provision of a **Black Start** service which would be specified via a **Black Start Contract**. Where an **EU Code User** does not offer to provide a cost for the provision of a **Black Start Capability**, **NGET** may make such a request if it considers **System** security to be at risk due to a lack of **Black Start** capability.

ECC.6.3.5.2 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** and **HVDC Systems**. For each **Power Station** or **HVDC System**, **NGET** will state in the **Bilateral Agreement** whether or not a **Black Start Capability** is required.

ECC.6.3.5.3 Where an **EU Code User** has entered into a **Black Start Contract** to provide a **Black Start Capability** in respect of a **Type C Power Generating Module** or **Type D Power Generating Module** (including **DC Connected Power Park Modules)** the following requirements shall apply.

1. The **Power-Generating Module** or **DC Connected Power Park Module** shall be capable of starting from shutdown without any external electrical energy supply within a time frame specified by **NGET** in the **Black Start Contract**.

2. Each **Power Generating Module** or **DC Connected Power Park Module** shall be able to synchronise within the frequency limits defined in ECC.6.1. and, where applicable, voltage limits specified in ECC.6.1.4;

3. The **Power Generating Module** or **DC Connected Power Park Module** shall be capable of connecting on to an unenergised **System**.

4. The **Power-Generating Module** or **DC Connected Power Park Module** shall be capable of automatically regulating dips in voltage caused by connection of demand;

5. The **Power Generating Module** or **DC Connected Power Park Module** shall:

be capable of **Block Load Capability**,

be capable of operating in **LFSM-O** and **LFSM-U**, as specified in ECC.6.3.7.1 and ECC.6.3.7.2

control **Frequency** in case of overfrequency and underfrequency within the whole **Active Power** output range between the **Minimum Regulating Level** and **Maximum Capacity** as well as at houseload operation levels

be capable of parallel operation of a few **Power Generating Modules** including **DC Connected Power Park Modules** within an isolated part of the **Total System** that is still supplying **Customers**, and control voltage automatically during the system restoration phase;

ECC.6.3.5.4 Each **HVDC System** or **Remote End HVDC Converter Station** which has a **Black Start Capability** shall be capable of energising the busbar of an AC substation to which another HV**DC Converter Station** is connected. The timeframe after shutdown of the **HVDC System** prior to energisation of the AC substation shall be pursuant to the terms of the **Black Start Contract**. The **HVDC System** shall be able to synchronise within the **Frequency** limits defined in ECC.6.1.2.1.2 and voltage limits defined in ECC.6.1.4.1 unless otherwise specified in the **Black Start Contract**. Wider **Frequency** and voltage ranges can be specified in the **Black Start Contract** in order to restore **System** security.

ECC.6.3.5.5 With regard to the capability to take part in operation of an isolated part of the **Total System** that is still supplying **Customers**:

1. **Power Generating Modules** including **DC Connected Power Park Modules** shall be capable of taking part in island operation if specified in the **Black Start Contract** required by **NGET** and:

   the **Frequency** limits for island operation shall be those specified in ECC.6.1.2,

   the voltage limits for island operation shall be those defined in ECC.6.1.4;

~~2.~~ **Power Generating Modules** including **DC Connected Power Park Modules** shall be able to operate in **Frequency Sensitive Mode** during island operation, as specified in ECC.6.3.7.3. In the event of a power surplus, **Power Generating Modules** including **DC Connected Power Park Modules** shall be capable of reducing the **Active Power** output from a previous operating point to any new operating point within the **Power Generating Module Performance Chart**. **Power Generating Modules** including **DC Connected Power Park Modules** shall be capable of reducing **Active Power** output as much as inherently technically feasible, but to at least 55 % of **Maximum Capacity**~~;~~

The method for detecting a change from interconnected system operation to island operation shall be agreed between the **EU Generator**, **NGET** and the **Relevant Transmission Licensee**. The agreed method of detection must not rely solely on **NGET**, **Relevant Transmission Licensee's** or **Network Operators** switchgear position signals;

(iv) **Power Generating Modules** including **DC Connected Power Park Modules** shall be able to operate in **LFSM-O** and **LFSM-U** during island operation, as specified in ECC.6.3.7.1 and ECC.6.3.7.2;

ECC.6.3.5.6 With regard to quick re-synchronisation capability:

1. In case of disconnection of the **Power Generating Module** including **DC Connected Power Park Modules** from the **System**, the **Power Generating Module** shall be capable of quick re-synchronisation in line with the **Protection** strategy agreed between **NGET** and/or **Network Operator** in co-ordination with the **Relevant Transmission Licensee**.~~-~~and the **Generator**;

2. A **Power Generating Module** including a **DC Connected Power Park Module** with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be capable of **Houseload Operation** from any operating point on~~-its-~~**Power Generating Module Performance Chart**. In this case, the identification of **Houseload Operation** must not be based solely on the **Total System's**~~the~~ switchgear position signals;

3. **Power Generating Modules** including **DC Connected Power Park Modules** shall be capable of **Houseload Operation**, irrespective of any auxiliary connection to the **Total System**. The minimum operation time shall be specified by **NGET**, taking into consideration the specific characteristics of prime mover technology.

ECC.6.3.6 CONTROL ARRANGEMENTS

ECC.6.3.6.1 **ACTIVE POWER** CONTROL

ECC.6.3.6.1.1 **Active Power** control in respect of **Power Generating Modules** including **DC Connected Power Park Modules**

ECC.6.3.6.1.1.1 **Type A Power Generating Modules** shall be equipped with a logic interface (input port) in order to cease **Active Power** output within five seconds following receipt of a signal from **NGET**. **NGET** shall specify the requirements for such facilities, including the need for remote operation, in the **Bilateral Agreement** where they are necessary for **System** reasons .

ECC.6.3.6.1.1.2 **Type B Power Generating Modules** shall be equipped with an interface (input port) in order to be able to reduce **Active Power** output following receipt of a signal from **NGET**.. **NGET** shall specify the requirements for such facilities, including the need for remote operation, in the **Bilateral Agreement** where they are necessary for **System** reasons.

ECC.6.3.6.1.1.3 **Type C** and **Type D Power Generating Modules** and **DC Connected Power Park Modules** shall be capable of adjusting the **Active Power** setpoint in accordance with instructions issued by **NGET.**

ECC.6.3.6.1.2 **Active Power** control in respect of **HVDC Systems** and **Remote End HVDC Converter Stations**

ECC.6.3.6.1.2.1 **HVDC Systems** shall be capable of adjusting the transmitted **Active Power** upon receipt of an instruction from **NGET** which shall be in accordance with the requirements of BC2.6.1.

ECC.6.3.6.1.2.2 The requirements for fast **Active Power** reversal (if required) shall be specified by **NGET**. Where **Active Power** reversal is specified in the **Bilateral Agreement**, each **HVDC System** and **Remote End HVDC Converter Station** shall be capable of operating from maximum import to maximum export in a time which is as fast as technically feasible or in a time that is no greater than 2 seconds except where a **HVDC Converter Station Owner** has justified to **NGET** that a longer reversal time is required.

ECC.6.3.6.1.2.3 Where an **HVDC System** connects various **Control Areas** or **Synchronous Areas**, each **HVDC System** or **Remote End HVDC Converter Station** shall be capable of responding to instructions issued by

NGET under the **Balancing Code** to modify the transmitted **Active Power** for the purposes of cross-border balancing.

ECC.6.3.6.1.2.4 An **HVDC System** shall be capable of adjusting the ramping rate of **Active Power** variations within its technical capabilities in accordance with instructions issued by **NGET** . In case of modification of **Active Power** according to ECC.6.3.15 and ECC.6.3.6.1.2.2, there shall be no adjustment of ramping rate.

ECC.6.3.6.1.2.5 If specified by **NGET**, in coordination with the **Relevant Transmission Licensees**, the control functions of an **HVDC System** shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM-O, LFSM-U and **Frequency** control. The triggering and blocking criteria shall be specified by **NGET**. ~~.~~

ECC.6.3.6.2 MODULATION OF ACTIVE POWER

ECC.6.3.6.2.1 Each **Power Generating Module** (including **DC Connected Power Park Modules**) and **Onshore HVDC Converters** at an **Onshore HVDC Converter Station** must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **National Electricity Transmission System**. For the avoidance of doubt each **Onshore HVDC Converter** at an **Onshore HVDC Converter Station** and/or **OTSDUW DC Converter** shall provide each **EU Code 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**. A **DC Connected Power Park Module** or **Offshore Power Generating Module** shall be capable of receiving and processing this signal within 100ms.

ECC.6.3.6.3 MODULATION OF REACTIVE POWER

ECC.6.3.6.3.1 Notwithstanding the requirements of ECC.6.3.2, each **Power Generating Module** or **HVDC Equipment** (and **OTSDUW Plant and Apparatus** at a **Transmission Interface Point** and **Remote End HVDC Converter** at an **HVDC Interface Point**) (as applicable) 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**.

ECC.6.3.7 FREQUENCY RESPONSE

ECC.6.3.7.1 Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)

ECC.6.3.7.1.1 Each **Power Generating Module** (including **DC Connected Power Park Modules**) and **HVDC Systems** shall be capable of reducing **Active Power** output in response to **Frequency** on the **Total System** when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as **Limited High Frequency Response**. The **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** shall be capable of operating stably during **LFSM-O** operation. However for a **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** operating in **Frequency Sensitive Mode** the requirements of LFSM-O shall apply when the frequency exceeds 50.5Hz.

ECC.6.3.7.1.2 (i) The rate of change of **Active Power** output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of **System Frequency** above 50.4Hz (ie a **Droop** of 10%) as shown in Figure ECC.6.3.7.1 below. This would not preclude a **EU Generator** or **HVDC System Owner** from designing their **Power Generating Module** with a **Droop** of less than 10% but in all cases the **Droop** should be 2% or greater..

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz. The **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** shall be capable of initiating a power **Frequency** response with an initial delay that is as short as possible. If the delay exceeds 2 seconds the **EU Generator** or **HVDC System Owner** shall justify the delay, providing technical evidence to **NGET**.

4. The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC System** output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes for the time of the **Frequency** increase above 50.4Hz.

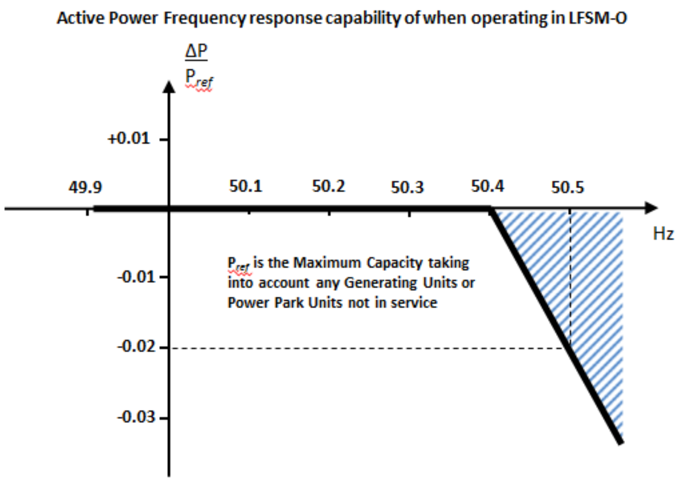


Figure ECC.6.3.7.1 – P_{ref} is the reference **Active Power** to which ΔP is related and ΔP is the change in **Active Power** output from the **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC System**. The **Power Generating Module** (including **DC Connected Power Park Modules** or **HVDC Systems)** has to provide a negative **Active Power** output change with a droop of 10% or less based on Pref.

ECC.6.3.7.1.3 Each **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** which is providing **Limited High Frequency Response (LFSM-O)** must continue to provide it until the **Frequency** has returned to or below 50.4Hz or until otherwise instructed by **NGET**. **EU Generators** in respect of **Gensets** and **HVDC Converter Station Owners** in respect of an **HVDC System** should also be aware of the requirements in BC.3.7.2.2.

ECC.6.3.7.1.4 Steady state operation below the **Minimum Stable Operating Level** in the case of **Power Generating Modules** including **DC Connected Power Park Modules** or **Minimum Active Power Transmission Capacity** in the case of **HVDC Systems** is not expected but if **System** operating conditions cause operation below the **Minimum Stable Operating Level** or **Minimum Active Power Transmission Capacity** which could give rise to operational difficulties for the **Power Generating Module** including a **DC Connected Power Park Module** or **HVDC Systems** then the **EU Generator** or HV**DC System Owner** shall be able to return the output of the **Power Generating Module** including a **DC Connected Power Park Module** to an output of not less than the **Minimum Stable Operating Level** or **HVDC System** to an output of not less than the **Minimum Active Power Transmission Capacity**.

ECC.6.3.7.1.5 All reasonable efforts should in the event be made by the **EU Generator** or **HVDC System Owner** to avoid such tripping provided that the **System Frequency** is below 52Hz in accordance with the requirements of ECC.6.1.2. If the **System Frequency** is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the **EU Generator** or **HVDC System Owner** is required to take action to protect its **Power Generating Modules** including **DC Connected Power Park Modules** or **HVDC Converter Stations**

ECC.6.3.7.2 Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)

ECC.6.3.7.2.1 Each **Type C Power Generating Module** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** operating in **Limited Frequency Sensitive Mode** shall be capable of increasing **Active Power** output in response to **System Frequency** when this falls below 49.5Hz. For the avoidance of doubt, the provision of this increase in **Active Power** output is not a mandatory **Ancillary Service** and it is not anticipated **Power Generating Modules** (including **DC Connected Power Park Modules**) or **HVDC Systems** are operated in an inefficient mode to facilitate delivery of **LFSM-U** response, but any inherent capability (where available) should be made without undue delay. The **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** shall be capable of stable operation during **LFSM-U Mode**. For example, a **EU Generator** which is operating with no headroom (eg it is operating at maximum output or is de-loading as part of a run down sequence and has no headroom) would not be required to provide **LFSM-U**.

ECC.6.3.7.2.2 (i) The rate of change of **Active Power** output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of **System Frequency** below 49.5Hz (ie a **Droop** of 10%) as shown in Figure ECC.6.3.7.2.2 below. This requirement only applies if the **Power Generating Module** has headroom and the ability to increase **Active Power** output. In the case of a **Power Park Module** or **DC Connected Power Park Module** the requirements of Figure ECC.6.3.7.2.2 shall be reduced pro-rata to the amount of **Power Park Units** in service and available to generate. For the avoidance of doubt, this would not preclude an **EU Generator** or **HVDC System Owner** from designing their **Power Generating Module** with a lower **Droop** setting, for example between 3 – 5%.

1. As much as possible of the proportional increase in **Active Power** output must result from the **Frequency** control device (or speed governor) action and must be achieved for **Frequencies** below 49.5 Hz. The **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** shall be capable of initiating a power **Frequency** response with minimal delay. If the delay exceeds 2 seconds the **EU Generator** or HV**DC System Owner** shall justify the delay, providing technical evidence to **NGET**).

2. The actual delivery of **Active Power Frequency Response** in **LFSM-U** mode shall take into account

The ambient conditions when the response is to be triggered

The operating conditions of the **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** in particular limitations on operation near **Maximum Capacity** or **Maximum HVDC Active Power Transmission Capacity** at low frequencies and the respective impact of ambient conditions as detailed in ECC.6.3.3.

The availability of primary energy sources.

3. In **LFSM_U Mode**, the **Power Generating Module** (including **DC Connected Power Park Modules**) and **HVDC Systems**, shall be capable of providing a power increase up to its **Maximum Capacity** or **Maximum HVDC Active Power Transmission Capacity** (as applicable).

Active Power Frequency response capability of when operating in LFSM-U

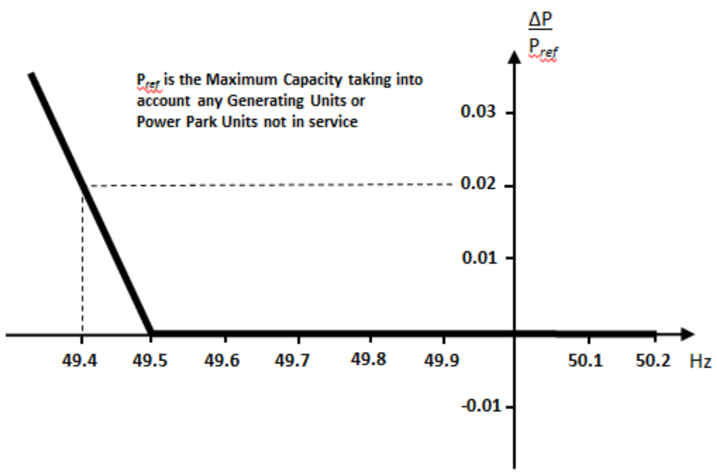


Figure ECC.6.3.7.2.2 – P_{ref} is the reference **Active Power** to which ΔP is related and ΔP is the change in **Active Power** output from the **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC System**. The **Power Generating Module** (including **DC Connected Power Park Modules** or **HVDC Systems)** has to provide a positive **Active Power** output change with a droop of 10% or less based on Pref.

ECC.6.3.7.3 <u>Frequency Sensitive Mode – (FSM)</u>

ECC.6.3.7.3.1 In addition to the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 each **Type C Power Generating Module** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** 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** including a **DC Connected Power Park Module**, the **Frequency** or speed control device(s) may be on the **Power Park Module** (including a **DC Connected Power Park Module**) or on each individual **Power Park Unit** (including a **Power Park Unit** within a **DC Connected Power Park Module**) or be a combination of both. The **Frequency** control device(s) (or speed governor(s)) must be designed and operated to the appropriate:

1. **European Specification**: or

2. 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 ECC.6.3.7.3.1 (a) (ii) will be notified to **NGET** by the **EU Generator** or **HVDC System Owner**:

(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

ECC.6.3.7.3.2 The **Frequency** control device (or speed governor) in co-ordination with other control devices must control each **Type C Power Generating Module** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems Active Power Output** or **Active Power** transfer capability with stability over the entire operating range of the **Power Generating Module** (including **DC Connected Power Park Modules**) or **HVDC Systems** ; and

ECC.6.3.7.3.3 **Type C** and **Type D Power Generating Modules** and **DC Connected Power Park Modules** shall also meet the following minimum requirements:

1. capable of providing **Active Power Frequency** response in accordance with the performance characteristic shown in Figure 6.3.7.3.3(a) and parameters in Table 6.3.7.3.3(a)

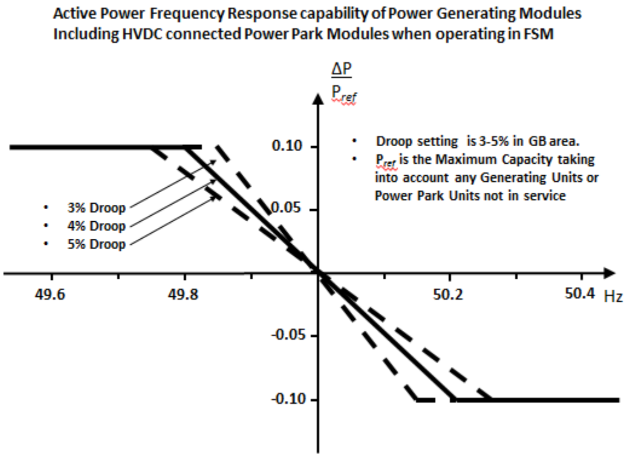


Figure 6.3.7.3.3(a) – **Frequency Sensitive Mode** capability of **Power Generating Modules** and **DC Connected Power Park Modules**

Parameter	Setting
Nominal **System Frequency**	50Hz

Active Power as a percentage of **Maximum Capacity** ($\frac{\lvert\Delta P_1\rvert}{P_{max}}$)	10%
Frequency Response Insensitivity in mHz ($\lvert\Delta f_i\rvert$)	±15mHz
Frequency Response Insensitivity as a percentage of nominal frequency ($\frac{\lvert\Delta f_i\rvert}{f_n}$)	±0.03%
Frequency Response Deadband in mHz	0 (mHz)
Droop (%)	3 – 5%

Table 6.3.7.3.3(a) – Parameters for **Active Power Frequency** response in **Frequency Sensitve Mode** including the mathematical expressions in Figure 6.3.7.3.3(a).

2. In satisfying the performance requirements specified in ECC.6.3.7.3(i) **EU Generators** in respect of each **Type C** and **Type D Power Generating Modules and DC Connected Power Park Module** should be aware:-

in the case of overfrequency, the **Active Power Frequency** response is limited by the **Minimum Regulating Level**,

in the case of underfrequency, the **Active Power Frequency** response is limited by the **Maximum Capacity,**

the actual delivery of **Active Power** frequency response depends on the operating and ambient conditions of the **Power Generating Module** (including **DC Connected Power Park Modules**) when this response is triggered, in particular limitations on operation near **Maximum Capacity** at low **Frequencies** as specified in ECC.6.3.3 and available primary energy sources.

The frequency control device (or speed governor) must also be capable of being set so that it operates with an overall speed **Droop** of between 3 – 5%. The **Frequency Response Deadband** and **Droop** must be able to be reselected repeatedly. For the avoidance of doubt, in the case of a **Power Park Module** (including **DC Connected Power Park Modules**) the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service.

3. In the event of a **Frequency** step change, each **Type C** and **Type D Power Generating Module** and **DC Connected Power Park Module** shall be capable of activating full and stable **Active Power Frequency** response (without undue power oscillations), in accordance with the performance characteristic shown in Figure 6.3.7.3.3(b) and parameters in Table 6.3.7.3.3(b).

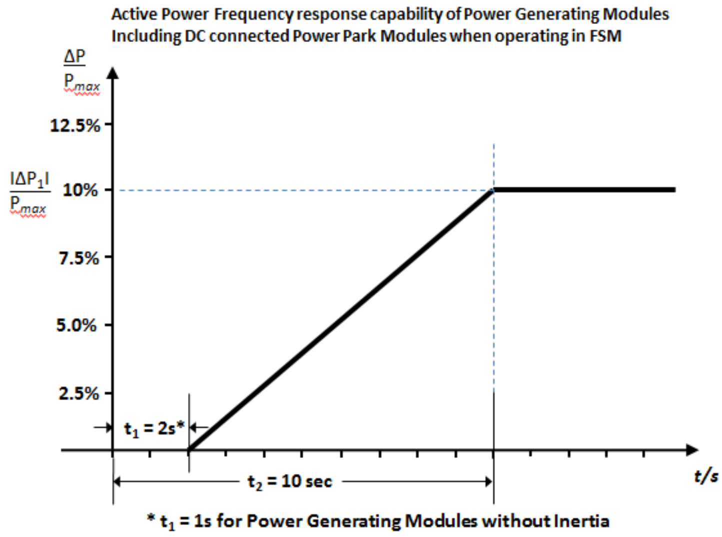


Figure 6.3.7.3.3(b) **Active Power Frequency Response** capability.

Parameter	Setting
Active Power as a percentage of **Maximum Capacity (frequency response range)** ($\frac{\lvert\Delta P_1\rvert}{P_{max}}$)	10%
Maximum admissible initial delay t_1 for **Power Generating Modules** (including **DC Connected Power Park Modules**) with inertia unless justified as specified in ECC.6.3.7.3.3 (iv)	2 seconds
Maximum admissible initial delay t_1 for **Power Generating Modules** (including **DC Connected Power Park Modules**) which do not contribute to **System** inertia unless justified as specified in ECC.6.3.7.3.3 (iv)	1 second
Activation time t_2	10 seconds

Table 6.3.7.3.3(b) – Parameters for full activation of **Active Power Frequency** response resulting from a **Frequency** step change. Table 6.3.7.3.3(b) also includes the mathematical expressions used in Figure 6.3.7.3.3(b).

4. The initial activation of **Active Power Primary Frequency** response shall not be unduly delayed. For **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) with inertia the delay in initial **Active Power Frequency** response shall not be greater than 2 seconds. For **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) without inertia, the delay in initial **Active Power Frequency** response shall not be greater than 1 second. If the **Generator** cannot meet this requirement they shall provide technical evidence to **NGET** demonstrating why a longer time is needed for the initial activation of **Active Power Frequency** response.

5. in the case of **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) other than the **Steam Unit** within a **CCGT Module** the combined effect of the **Frequency Response Insensitivity** and **Frequency Response Deadband** of the **Frequency** control device (or speed governor) 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 **Frequency Response Deadband** should be set to an appropriate value consistent with the requirements of ECC.6.3.7.3.5(ii) and the requirements of BC3.7.2.2 for the provision of **LFSM-O** taking account of any **Frequency Response Insensitivity** of the Frequency control device (or speed governor);

ECC.6.3.7.3.4 **HVDC Systems** shall also meet the following minimum requirements:

1. **HVDC Systems** shall be capable of responding to **Frequency** deviations in each connected AC **System** by adjusting their **Active Power** import or export as shown in Figure 6.3.7.3.4(a) with the corresponding parameters in Table 6.3.7.3.4(a).

Active Power Frequency response capability of HVDC systems when operating in FSI

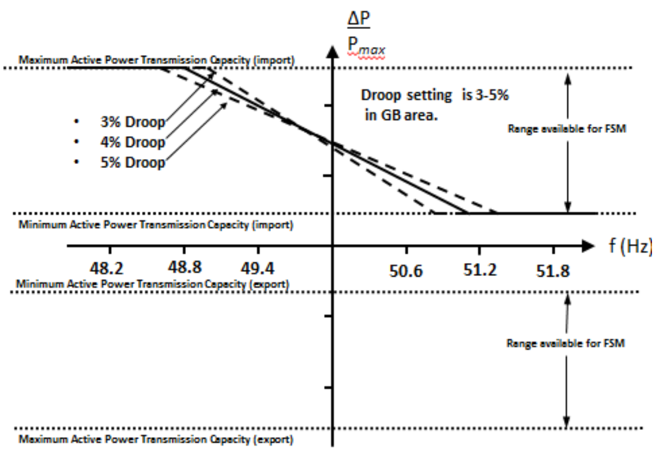


Figure 6.3.7.3.4(a) – **Active Power** frequency response capability of a **HVDC System** operating in **Frequency Sensitive Mode** (FSM). ΔP is the change in active power output from the **HVDC System**..

Parameter	Setting
Frequency Response Deadband	0
Droop S1 and S2 (upward and downward regulation) where S1=S2.	3 – 5%
Frequency Response Insensitivity	±15mHz

Table 6.3.7.3.4(a) – Parameters for **Active Power Frequency** response in **FSM** including the mathematical expressions in Figure 6.3.7.3.4.

2. Each **HVDC System** shall be capable of adjusting the **Droop** for both upward and downward regulation and the **Active Power** range over which **Frequency Sensitive Mode** of operation is available as defined in ECC.6.3.7.3.4.

3. In addition to the requirements in ECC.6.3.7.4(i) and ECC.6.3.7.4(ii) each **HVDC System** shall be capable of:-

delivering the response as soon as technically feasible

delivering the response on or above the solid line in Figure 6.3.7.3.4(b) in accordance with the parameters shown in Table 6.3.7.3.4(b)

initiating the delivery of **Primary Response** in no less than 0.5 seconds unless otherwise agreed with **NGET**. Where the initial delay time (t_1 – as shown in Figure 6.3.7.3.4(b)) is longer than 0.5 seconds the **HVDC Converter Station Owner** shall reasonably justify it to **NGET**.

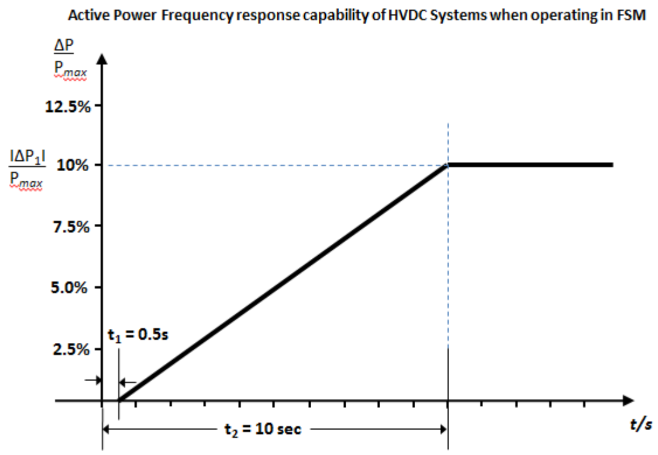


Figure 6.3.7.3.4(b) **Active Power Frequency Response** capability of a **HVDC System**. ΔP is the change in **Active Power** triggered by the step change in frequency

Parameter	Setting
Active Power as a percentage of **Maximum Capacity (frequency response range)** ($\frac{\lvert\Delta P_1\rvert}{P_{max}}$)	10%
Maximum admissible delay t_1	0.5 seconds
Maximum admissible time for full activation t_2, unless longer activation times are agreed with **NGET**	10 seconds

Table 6.3.7.3.4(b) – Parameters for full activation of **Active Power Frequency** response resulting from a **Frequency** step change.

4. For **HVDC Systems** connecting various **Synchronous Areas**, each **HVDC System** shall be capable of adjusting the full **Active Power Frequency Response** when operating in **Frequency Sensitive Mode** at any time and for a continuous time period. In addition, the **Active Power** controller of each **HVDC System** shall not have any adverse impact on the delivery of frequency response.

ECC.6.3.7.3.5 For **HVDC Systems** and **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**), other than the **Steam Unit** within a **CCGT Module** the combined effect of the **Frequency Response Insensitivity** and **Frequency Response Deadband** of the **Frequency** control device (or speed governor) 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 **Frequency Response Deadband** should be set to an appropriate value consistent with the requirements of ECC.6.3.7.3.5(ii) and the requirements of BC3.7.2.2 for the provision of **LFSM-O** taking account of any **Frequency Response Insensitivity** of the **Frequency** control device (or speed governor);

(i) With regard to disconnection due to underfrequency, **EU Generators** responsible for **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) capable of acting as a load, including but not limited to **Pumped Storage** and tidal **Power Generating Modules**, **HVDC Systems** and **Remote End HVDC Converter Stations** , shall be capable of disconnecting their load in case of underfrequency which will be agreed with **NGET**. For the avoidance of doubt this requirement does not apply to station auxiliary supplies; **EU Generators** in respect of **Type C** and **Type D Pumped Storage Power Generating Modules** should also be aware of the requirements in OC.6.6.6.

1. Where a **Type C** or **Type D Power Generating Module**, **DC Connected Power Park Module** or **HVDC System** becomes isolated from the rest of the **Total System** but is still supplying **Customers**, the **Frequency** control device (or speed governor) must also be able to control **System Frequency** below 52Hz unless this causes the **Type C** or **Type D Power Generating Module** or **DC Connected Power Park Module** to operate below its **Minimum Regulating Level** or **Minimum Active Power Transmission Capacity** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt **Power Generating Modules** (including **DC Connected Power Park Modules**) and **HVDC Systems** are only required to operate within the **System Frequency** range 47 - 52 Hz as defined in ECC.6.1.2 and for converter based technologies, the remaining island contains sufficient fault level for effective commutation;

2. Each **Type C** and **Type D Power Generating Module** and **HVDC Systems** shall have the facility to modify the **Target Frequency** setting either continuously or in a maximum of 0.05Hz steps over at least the range 50 ±0.1Hz should be provided in the unit load controller or equivalent device.

ECC.6.3.7.3.6 In addition to the requirements of ECC.6.3.7.3 each **Type C** and **Type D Power Generating Module** and **HVDC System** shall be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix A3.

ECC.6.3.7.3.7 For the avoidance of doubt, the requirements of Appendix A3 do not apply to **Type A** and **Type B Power Generating Modules**.

ECC.6.3.8 <u>EXCITATION AND VOLTAGE CONTROL PERFORMANCE REQUIREMENTS</u>

ECC.6.3.8.1 <u>Excitation Performance Requirements for Type B Synchronous Power Generating Modules</u>

ECC.6.3.8.1.1 Each **Synchronous Generating Unit** within a **Type B Synchronous Power Generating Module** shall be equipped with a permanent automatic excitation control system that shall have the capability to provide constant terminal voltage at a selectable setpoint without instability over the entire operating range of the **Type B Synchronous Power Generating Module**.

ECC.6.3.8.1.2 In addition to the requirements of ECC.6.3.8.1.1, **NGET** or the relevant **Network Operator** will specify if the control system of the **Type B Synchronous Power Generating Module** shall contribute to voltage control or **Reactive Power** control or **Power Factor** control at the **Grid Entry Point** or **User System Entry Point** (or other defined busbar). The performance requirements of the control system including slope (where applicable) shall be agreed between **NGET** and/or the relevant **Network Operator** and the **EU Generator**.

ECC.6.3.8.2 <u>Voltage Control Requirements for **Type B Power Park Modules**</u>

ECC.6.3.8.2.1 **NGET** or the relevant **Network Operator** will specify if the control system of the **Type B Power Park Module** shall contribute to voltage control or **Reactive Power** control or **Power Factor** control at the **Grid Entry Point** or **User System Entry Point** (or other defined busbar). The performance requirements of the control system including slope (where applicable) shall be agreed between **NGET** and/or the relevant **Network Operator** and the **EU Generator**.

ECC.6.3.8.3 <u>Excitation Performance Requirements for **Type C** and **Type D Onshore Synchronous Power Generating Modules**</u>

ECC.6.3.8.3.1 Each **Synchronous Generating Unit** within a **Type C** and **Type D Onshore Synchronous Power Generating Modules** shall be equipped with a permanent automatic excitation control system that shall have the capability to provide constant terminal voltage control at a selectable setpoint without instability over the entire operating range of the **Synchronous Power Generating Module**.

ECC.6.3.8.3.2 The requirements for excitation control facilities are specified in ECC.A.6. Any site specific requirements shall be specified by **NGET** or the relevant **Network Operator**.

ECC.6.3.8.3.3 Unless otherwise required for testing in accordance with OC5.A.2, the automatic excitation control system of an **Onshore Synchronous Power Generating Module** shall always be operated such that it controls the **Onshore Synchronous Generating Unit** terminal voltage to a value that is

1. equal to its rated value: or

2. only where provisions have been made in the **Bilateral Agreement**, greater than its rated value.

ECC.6.3.8.3.4 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 otherwise agreed with **NGET** or the relevant **Network Operator**. Operation of such control facilities will be in accordance with the provisions contained in **BC2**.

ECC.6.3.8.3.5 The excitation performance requirements for **Offshore Synchronous Power Generating Modules** with an **Offshore Grid Entry Point** shall be specified by **NGET**.

ECC.6.3.8.4 <u>Voltage Control Performance Requirements for **Type C** and **Type D Onshore Power Park Modules**, **Onshore HVDC Converters** and **OTSUW Plant and Apparatus** at the **Interface Point**</u>

ECC.6.3.8.4.1 Each **Type C** and **Type D Onshore Power Park Module**, **Onshore HVDC Converter** and **OTSDUW Plant and Apparatus** shall be fitted with a continuously acting automatic control system to provide control of the voltage at the **Grid Entry Point** or **User System Entry Point** (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) without instability over the entire operating range of the **Onshore Power Park Module**, or **Onshore HVDC Converter** 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 **Grid Entry Point** or **User System Entry Point**. In the case of an **Onshore HVDC Converter** at a **HVDC Converter Station** any **Plant** or **Apparatus** used in the provisions of such voltage control may be located at any point within the **User's Plant and Apparatus** including the **Grid Entry Point** or **User System Entry 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**. When operating below 20% **Maximum Capacity** the automatic control system may continue to provide voltage control using 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 below 20% of **Active Power** output and the non-shaded area above 20% of **Active Power** output in Figure ECC.6.3.2.5(c) and Figure ECC.6.3.2.7(b) 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 HVDC Converters** at an **Onshore HVDC Converter Station**, **OTSDUW Plant and Apparatus** at the **Interface Point** are defined in ECC.A.7.

ECC.6.3.8.4.3 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 voltage control system they will be disabled unless otherwise agreed with **NGET** or the relevant **Network Operator**. Operation of such control facilities will be in accordance with the provisions contained in BC2. Where **Reactive Power** output control modes and constant **Power Factor** control modes have been fitted within the voltage control system they shall be required to satisfy the requirements of ECC.A.7.3 and ECC.A.7.4.

ECC.6.3.8.5 <u>Excitation Control Performance requirements applicable to AC Connected **Offshore Synchronous Power Generating Modules** and voltage control performance requirements applicable to AC connected **Offshore Power Park Modules**, **DC Connected Power Park Modules** and **Remote End HVDC Converters**</u>

ECC.6.3.8.5.1 A continuously acting automatic control system is required to provide control of **Reactive Power** (as specified in ECC.6.3.2.5 and ECC.6.3.2.6) at the **Offshore Grid Entry Point** (or **HVDC Interface Point** in the case of **Configuration 1 DC Connected Power Park Modules** and **Remote End HVDC Converters**) without instability over the entire operating range of the AC connected **Offshore Synchronous Power Generating Module** or **Configuration 1 AC connected Offshore Power Park Module** or **Configuration 1 DC Connected Power Park Modules** or **Remote End HVDC Converter**. The performance requirements for this automatic control system will be specified by **NGET** which would be consistent with the requirements of ECC.6.3.2.5 and ECC.6.3.2.6.

ECC.6.3.8.5.2 A continuously acting automatic control system is required to provide control of **Reactive Power** (as specified in ECC.6.3.2.8) at the **Offshore Grid Entry Point** (or **HVDC Interface Point** in the case of **Configuration 2 DC Connected Power Park Modules**) without instability over the entire operating range of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Modules.** otherwise the requirements of ECC.6.3.2.6 shall apply. The performance requirements for this automatic control system are specified in ECC.A.8

ECC.6.3.8.5.3 In addition to ECC.6.3.8.5.1 and ECC.6.3.8.5.2 the requirements for excitation or voltage control facilities, including **Power System Stabilisers**, where these are necessary for system reasons, will be specified by **NGET**. Reference is made to on-load commissioning witnessed by **NGET** in BC2.11.2.

ECC.6.3.9 <u>STEADY STATE LOAD INACCURACIES</u>

ECC.6.3.9.1 The standard deviation of **Load** error at steady state **Load** over a 30 minute period must not exceed 2.5 per cent of a **Type C** or **Type D Power Generating Modules** (including a **DC Connected Power Park Module**) **Maximum Capacity**. Where a **Type C** or **Type D Power Generating Module** (including a **DC Connected Power Park Module**) 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.

ECC.6.3.10 <u>NEGATIVE PHASE SEQUENCE LOADINGS</u>

ECC.6.3.10.1 In addition to meeting the conditions specified in ECC.6.1.5(b), each **Synchronous Power Generating Module** 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**.

ECC.6.3.11 <u>NEUTRAL EARTHING</u>

ECC.6.3.11 At nominal **System** voltages of 110kV and above the higher voltage windings of a transformer of a **Power Generating Module** or **HVDC Equipment** 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 ECC.6.2.1.1 (b) will be met on the **National Electricity Transmission System** at nominal **System** voltages of 110kV and above.

ECC.6.3.12 <u>FREQUENCY AND VOLTAGE DEVIATIONS</u>

ECC.6.3.12.1 As stated in ECC.6.1.2, the **System Frequency** could rise to 52Hz or fall to 47Hz. Each **Power Generating Module** (including **DC Connected Power Park Modules**) must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.2 unless **NGET** has specified any requirements for combined **Frequency** and voltage deviations which are required to ensure the best use of technical capabilities of **Power Generating Modules** (including **DC Connected Power Park Modules**) if required to preserve or restore system security.- Notwithstanding this requirement, **EU Generators** should also be aware of the requirements of ECC.6.3.13.

ECC.6.3.13 FREQUENCY, RATE OF CHANGE OF FREQUENCY AND VOLATGE PROTECTION SETTING ARRANGEMENTS

ECC.6.3.13.1 **EU Generators** (including in respect of **OTSDUW Plant and Apparatus**) and **HVDC** System Owners will be responsible for protecting all their **Power Generating Modules** (and **OTSDUW Plant and Apparatus**) or **HVDC Equipment** against damage should **Frequency** excursions outside the range 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the **EU Generator** or **HVDC System Owner** to decide whether to disconnect his **Apparatus** for reasons of safety of **Apparatus**, **Plant** and/or personnel.

ECC.6.3.13.2 Each **Power Generating Module** when connected and synchronised to the **System**, shall be capable of withstanding without tripping a rate of change of **Frequency** up to and including 1 Hz per second as measured over a rolling 500 milliseconds period. Voltage dips may cause localised rate of change of **Frequency** values in excess of 1 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **Power Generating Modules** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

ECC.6.3.13.3 Each **HVDC System** and **Remote End HVDC Converter Station** when connected and synchronised to the **System**, shall be capable of withstanding without tripping a rate of change of **Frequency** up to and including ±2.5Hz per second as measured over the previous 1 second period. Voltage dips may cause localised rate of change of **Frequency** values in excess of ±2.5 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **HVDC Systems** and **Remote End HVDC Converter Stations** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

ECC.6.3.13.4 Each **DC Connected Power Park Module** when connected to the **System,** shall be capable of withstanding without tripping a rate of change of **Frequency** up to and including ±2.0Hz per second as measured over the previous 1 second period. **Voltage** dips may cause localised rate of change of **Frequency** values in excess of ±2.0 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **DC Connected Power Park Modules** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

ECC.6.3.13.5 As stated in ECC.6.1.2, the **System Frequency** could rise to 52Hz or fall to 47Hz and the **System** voltage at the **Grid Entry Point** or **User System Entry Point** could rise or fall within the values outlined in ECC.6.1.4. Each **Type C** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.2 and voltage range as defined in ECC.6.1.4 unless **NGET** has agreed to any simultaneous overvoltage and underfrequency relays and/or simultaneous undervoltage and over frequency relays which will trip such **Power Generating Module** (including **DC Connected Power Park Modules**), and any constituent element within this **Frequency** or voltage range.

ECC.6.3.14 FAST START CAPABILITY

ECC.6.3.14.1 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**.

ECC.6.3.15 FAULT RIDE THROUGH

ECC.6.3.15.1 General **Fault Ride Through** requirements, principles and concepts applicable to **Type B**, **Type C** and **Type D Power Generating Modules** and **OTSDUW Plant and Apparatus** subject to faults up to 140ms in duration

ECC.6.3.15.1.1 ECC.6.3.15.1 – ECC.6.3.15.8 section sets out the **Fault Ride Through** requirements on **Type B**, **Type C** and **Type D Power Generating Modules**, **OTSDUW Plant and Apparatus** and **HVDC Equipment** that shall apply in the event of a fault lasting up to 140ms in duration.

ECC.6.3.15.1.2 Each **Power Generating Module**, **Power Park Module**, **HVDC Equipment** and **OTSDUW Plant and Apparatus** is required to remain connected and stable for any balanced and unbalanced fault where the voltage at the **Grid Entry Point** or **User System Entry Point** or (**HVDC Interface Point** in the case of **Remote End DC Converter Stations** or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) remains on or above the heavy black line defined in sections ECC.6.3.15.2 – ECC.6.3.15.7 below.

ECC.6.3.15.1.3 The voltage against time curves defined in ECC.6.3.15.2 – ECC.6.3.15.7 expresses the lower limit (expressed as the ratio of its actual value and its reference 1pu) of the actual course of the phase to phase voltage (or phase to earth voltage in the case of asymmetrical/unbalanced faults) on the **System** voltage level at the **Grid Entry Point** or **User System Entry Point** (or **HVDC Interface Point** in the case of **Remote End HVDC Converter Stations** or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) during a symmetrical or asymmetrical/unbalanced fault, as a function of time before, during and after the fault.

ECC.6.3.15.2 Voltage against time curve and parameters applicable to **Type B Synchronous Power Generating Modules**

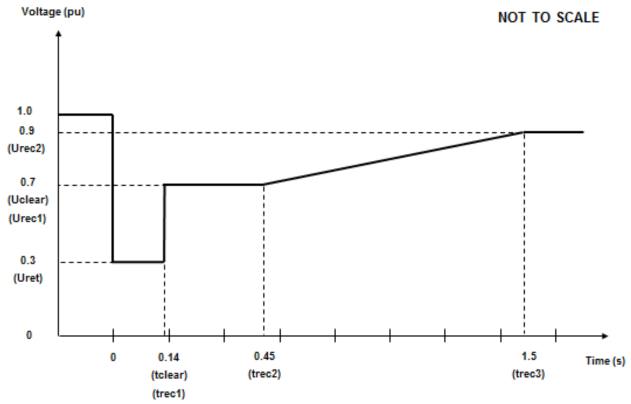


Figure ECC.6.3.15.2 - Voltage against time curve applicable to **Type B Synchronous Power Generating Modules**

Voltage parameters (pu)		Time parameters (seconds)	
Uret	0.3	tclear	0.14
Uclear	0.7	trec1	0.14
Urec1	0.7	trec2	0.45
Urec2	0.9	trec3	1.5

Table ECC.6.3.15.2 Voltage against time parameters applicable to **Type B Synchronous Power Generating Modules**

ECC.6.3.15.3 Voltage against time curve and parameters applicable to **Type C** and **D Synchronous Power Generating Modules** connected below 110kV

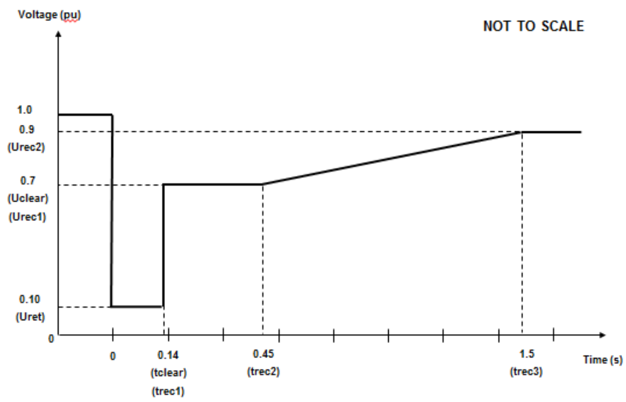


Figure ECC.6.3.15.3 - Voltage against time curve applicable to **Type C** and **D Synchronous Power Generating Modules** connected below 110kV

Voltage parameters (pu)		Time parameters (seconds)	
Uret	0.1	tclear	0.14
Uclear	0.7	trec1	0.14
Urec1	0.7	trec2	0.45
Urec2	0.9	trec3	1.5

Table ECC.6.3.15.3 Voltage against time parameters applicable to **Type C** and **D Synchronous Power Generating Modules** connected below 110kV

ECC.6.3.15.4 Voltage against time curve and parameters applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

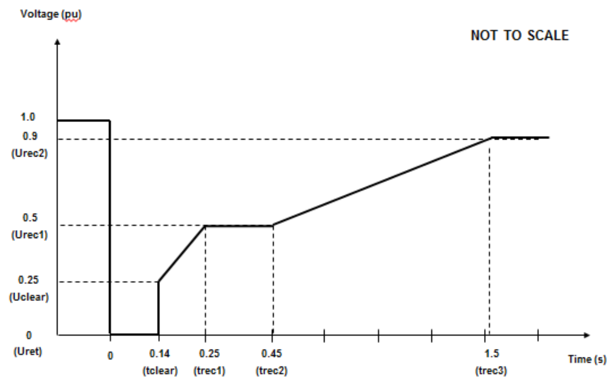


Figure ECC.6.3.15.4 - Voltage against time curve applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

Voltage parameters (pu)		Time parameters (seconds)	
Uret	0	tclear	0.14
Uclear	0.25	trec1	0.25
Urec1	0.5	trec2	0.45
Urec2	0.9	trec3	1.5

Table ECC.6.3.15.4 Voltage against time parameters applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

ECC.6.3.15.5 Voltage against time curve and parameters applicable to **Type B**, **C** and **D Power Park Modules** connected below 110kV

Figure ECC.6.3.15.5 - Voltage against time curve applicable to **Type B**, **C** and **D Power Park Modules** connected below 110kV

Voltage parameters (pu)		**Time parameters (seconds)**	
Uret	0.10	tclear	0.14
Uclear	0.10	trec1	0.14
Urec1	0.10	trec2	0.14
Urec2	0.85	trec3	2.2

Table ECC.6.3.15.5 Voltage against time parameters applicable to **Type B**, **C** and **D Power Park Modules** connected below 110kV

ECC.6.3.15.6 Voltage against time curve and parameters applicable to **Type D Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or above 110kV, **DC Connected Power Park Modules** at the **HVDC Interface Point** or **OTSDUW Plant and Apparatus** at the **Interface Point**.

Figure ECC.6.3.15.6 - Voltage against time curve applicable to **Type D Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or above 110kV, **DC Connected Power Park Modules** at the **HVDC Interface Point** or **OTSDUW Plant and Apparatus** at the **Interface Point**.

Voltage parameters (pu)		**Time parameters (seconds)**	
Uret	0	tclear	0.14
Uclear	0	trec1	0.14
Urec1	0	trec2	0.14
Urec2	0.85	trec3	2.2

Table ECC.6.3.15.6   Voltage against time parameters applicable to a **Type D Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or above 110kV, **DC Connected Power Park Modules** at the **HVDC Interface Point** or **OTSDUW Plant and Apparatus** at the **Interface Point**.

ECC.6.3.15.7 <u>Voltage against time curve and parameters applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**</u>

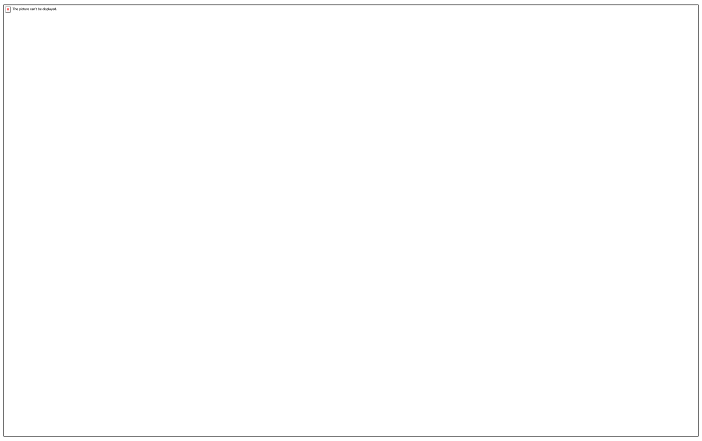


Figure ECC.6.3.15.7 - Voltage against time curve applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**

Voltage parameters (pu)		**Time parameters (seconds)**	
Uret	0	tclear	0.14
Uclear	0	trec1	0.14
Urec1	0	trec2	0.14
Urec2	0.85	trec3	2.2

Table ECC.6.3.15.7 Voltage against time parameters applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**

ECC.6.3.15.8 In addition to the requirements in ECC.6.3.15.1 – ECC.6.3.15.7:

1. Each **Type B**, **Type C** and **Type D Power Generating Module** at the **Grid Entry Point** or **User System Entry Point**, **HVDC Equipment** (or **OTSDUW Plant and Apparatus** at the **Interface Point**) shall be capable of satisfying the above requirements when operating at **Rated MW** output and maximum leading **Power Factor**.
2. **NGET** will specify upon request by the **User** the pre-fault and post fault short circuit capacity (in MVA) at the **Grid Entry Point** or **User System Entry Point** (or **HVDC Interface Point** in the case of a remote end **HVDC Converter Stations** or **Interface Point** in the case of **OTSDUW Plant and Apparatus**).
3. The pre-fault voltage shall be taken to be 1.0pu and the post fault voltage shall not be less than 0.9pu.
4. To allow a **User** to model the **Fault Ride Through** performance of its **Type B**, **Type C** and/or **Type D Power Generating Modules** or **HVDC Equipment**, **NGET** will provide additional network data as may reasonably be required by the **EU Code User** to

undertake such study work in accordance with PC.A.8. Alternatively, **NGET** may provide generic values derived from typical cases.

(v) **NGET** will publish fault level data under maximum and minimum demand conditions in the **Electricity Ten Year Statement**.

(vi) Each **EU Generator** (in respect of **Type B**, **Type C**, **Type D Power Generating Modules** and **DC Connected Power Park Modules**) and **HVDC System Owners** (in respect of **HVDC Systems**) shall satisfy the requirements in ECC.6.3.15.8(i) – (vii) unless the protection schemes and settings for internal electrical faults trips the **Type B**, **Type C** and **Type D Power Generating Module**, **HVDC Equipment** (or **OTSDUW Plant and Apparatus**) from the **System**. The protection schemes and settings should not jeopardise **Fault Ride Through** performance as specified in ECC.6.3.15.8(i) – (vii). The undervoltage protection at the **Grid Entry Point** or **User System Entry Point** (or **HVDC Interface Point** in the case of a **Remote End HVDC Converter Stations** or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) shall be set by the **EU Generator** (or **HVDC System Owner** or **OTSDUA** in the case of **OTSDUW Plant and Apparatus**) according to the widest possible range unless **NGET** and the **EU Code User** have agreed to narrower settings. All protection settings associated with undervoltage protection shall be agreed between the **EU Generator** and/or **HVDC System Owner** with **NGET** and **Relevant Transmission Licensee's** and relevant **Network Operator** (as applicable).

(vii) Each **Type B**, **Type C** and **Type D Power Generating Module**, **HVDC System** and **OTSDUW Plant and Apparatus** at the **Interface Point** shall be designed such that upon clearance of the fault on the **Onshore Transmission System** and within 0.5 seconds of restoration of the voltage at the **Grid Entry Point** or **User System Entry Point** or **HVDC Interface Point** in the case of a **Remote End HVDC Converter Stations** or **Interface Point** in the case of **OTSDUW Plant and Apparatus** to 90% of nominal voltage or greater, **Active Power** output (or **Active Power** transfer capability in the case of **OTSDW Plant and Apparatus** or **Remote End HVDC Converter Stations**) shall be restored to at least 90% of the level immediately before the fault. Once **Active Power** output (or **Active Power** transfer capability in the case of **OTSDUW Plant and Apparatus** or **Remote End HVDC Converter Stations**) has been restored to the required level, **Active Power** oscillations shall be acceptable provided that:

1. 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
2. The oscillations are adequately damped.
3. In the event of power oscillations, **Power Generating Modules** shall retain steady state stability when operating at any point on **the Power Generating Module Performance Chart**.

For AC Connected **Onshore** and **Offshore Power Park Modules** comprising switched reactive compensation equipment (such as mechanically switched capacitors and reactors), such switched reactive compensation equipment 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.

ECC.6.3.15.9 General Fault Ride Through requirements for faults in excess of 140ms in duration.

ECC.6.3.15.9.1 General Fault Ride Through requirements applicable to HVDC Equipment and OTSDUW DC Converters subject to faults and voltage dips in excess of 140ms.

ECC.6.3.15.9.1.1 The requirements applicable to **HVDC Equipment** including **OTSDUW DC Converters** subject to faults and voltage disturbances at the **Grid Entry Point** or **User System Entry Point** or **Interface Point** or **HVDC Interface Point**, including **Active Power** transfer capability shall be specified in the **Bilateral Agreement**.

ECC.6.3.15.9.2 Fault Ride Through requirements for Type C and Type D Synchronous Power Generating Modules and Type C and Type D Power Park Modules and OTSDUW Plant and Apparatus subject to faults and voltage disturbances on the Onshore Transmission System in excess of 140ms

ECC.6.3.15.9.2.1 The **Fault Ride Through** requirements for **Type C** and **Type D Synchronous Power Generating Modules** subject to faults and voltage disturbances on the **Onshore Transmission System** in excess of 140ms are defined in ECC.6.3.15.9.2.1(a) and the **Fault Ride Through Requirements** for **Power Park Modules** and **OTSDUW Plant and Apparatus** subject to faults and voltage disturbances on the **Onshore Transmission System** greater than 140ms in duration are defined in ECC.6.3.15.9.2.1(b).

(a) Requirements applicable to **Synchronous Power Generating Modules** subject to **Supergrid Voltage** dips on the **Onshore Transmission System** greater than 140ms in duration.

In addition to the requirements of ECC.6.3.15.1 – ECC.6.3.15.8 each **Synchronous Power Generating Module** shall:

(i) remain transiently stable and connected to the **System** without tripping of any **Synchronous Power Generating Module** 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 ECC.6.3.15.9(a) Appendix 4 and Figures EA.4.3.2(a), (b) and (c) provide an explanation and illustrations of Figure ECC.6.3.15.9(a); and,

Figure ECC.6.3.15.9(a)

(ii) provide **Active Power** output at the **Grid Entry Point**, during **Supergrid Voltage** dips on the **Onshore Transmission System** as described in Figure ECC.6.3.15.9(a), at least in proportion to the retained balanced voltage at the **Onshore Grid Entry Point** (for **Onshore Synchronous Power Generating Modules)** or **Interface Point** (for **Offshore Synchronous Power Generating Modules**) (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 ECC.6.1.4) without exceeding the transient rating limits of the **Synchronous Power Generating Module** and,

(iii) restore **Active Power** output following **Supergrid Voltage** dips on the **Onshore Transmission System** as described in Figure ECC.6.3.15.9(a), within 1 second of restoration of the voltage to 1.0pu of the nominal voltage at the:

Onshore Grid Entry Point for directly connected **Onshore Synchronous Power Generating Modules** or,

Interface Point for **Offshore Synchronous Power Generating Modules**
or,
User System Entry Point for **Embedded Onshore Synchronous Power Generating Modules**
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 ECC.6.1.5 (b) and ECC.6.1.6.

(b) Requirements applicable to **Type C** and **Type D Power Park Modules** and **OTSDUW Plant and Apparatus** (excluding **OTSDUW DC Converters**) subject to **Supergrid Voltage** dips on the **Onshore Transmission System** greater than 140ms in duration.

In addition to the requirements of ECC.6.3.15.5, ECC.6.3.15.6 and ECC.6.3.15.8 (as applicable) each **OTSDUW Plant and Apparatus** or each **Power Park Module** and / or any constituent **Power Park Unit**, 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 ECC.6.3.15.9(b). Appendix 4 and Figures EA.4.3.4 (a), (b) and (c) provide an explanation and illustrations of Figure ECC.6.3.15.9(b) ; and,

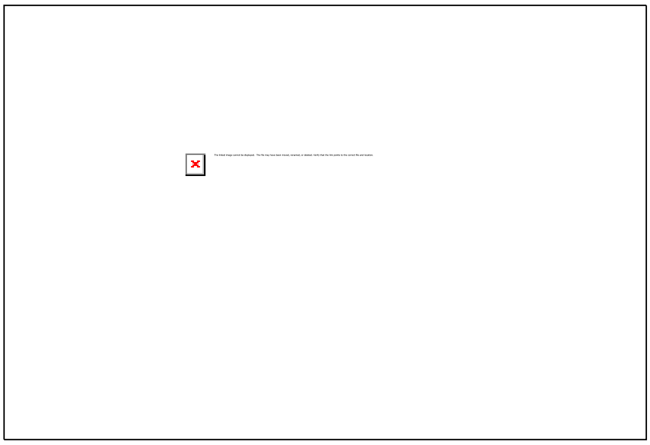


Figure ECC.6.3.15.9(b)

(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 ECC.6.3.15.9(b), 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 ECC.6.3.15.9(b) that restricts the **Active Power** output or in the case of an **OTSDUW Active Power** transfer capability below this level.

(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 ECC.6.3.15.9(b), 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 ECC.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 ECC.6.3.15.9(b) 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 ECC.6.1.5 (b) and ECC.6.1.6.

ECC.6.3.15.10 Other **Fault Ride Through** Requirements

(i) In the case of a **Power Park Module**, the requirements in ECC.6.3.15.9 do not apply when the **Power Park Module** is operating at less than 5% of its **Rated MW** or during very high primary energy source conditions when more than 50% of the **Power Park 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 ECC.6.1.5(b) and ECC.6.1.6, each **Non-Synchronous Generating Unit**, **OTSDUW Plant and Apparatus** or **Power Park Module** and any constituent **Power Park Unit** thereof will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by **System Back-Up Protection** on the **Onshore Transmission System** operating at **Supergrid Voltage**.

1. **Generators** in respect of **Type B**, **Type C** and **Type D Power Park Modules** and **HVDC System Owners** are required to confirm to **NGET**, their repeated ability to operate through balanced and unbalanced faults and **System** disturbances each time the voltage at the **Grid Entry Point** or **User System Entry Point** falls outside the limits specified in ECC.6.1.4. Demonstration of this capability would be satisfied by **EU Generators** and **HVDC System Owners** supplying the protection settings of their plant, informing **NGET** of the maximum number of repeated operations that can be performed under such conditions and any limiting factors to repeated operation such as protection or thermal rating; and
2. Notwithstanding the requirements of ECC.6.3.15(v), **Power Generating Modules** shall be capable of remaining connected during single phase or three phase auto-reclosures to the **National Electricity Transmission System** and operating without power reduction as long as the voltage and frequency remain within the limits defined in ECC.6.1.4 and ECC.6.1.2; and
3. For the avoidance of doubt the requirements specified in ECC.6.3.15 do not apply to **Power Generating Modules** connected to either an unhealthy circuit and/or islanded from the **Transmission System** even for delayed auto reclosure times.
4. 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

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**.

ECC.6.3.15.11 HVDC System Robustness

6.3.15.11.1 The **HVDC System** shall be capable of finding stable operation points with a minimum change in **Active Power** flow and voltage level, during and after any planned or unplanned change in the **HVDC System** or AC **System** to which it is connected. **NGET** shall specify the changes in the System conditions for which the **HVDC Systems** shall remain in stable operation.

6.3.15.11.2 The **HVDC System** owner shall ensure that the tripping or disconnection of an **HVDC Converter Station**, as part of any multi-terminal or embedded **HVDC System**, does not result in transients at the **Grid Entry Point** or **User System Entry Point** beyond the limit specified by **NGET** in co-ordination with the **Relevant Transmission Licensee**.

6.3.15.11.3 The **HVDC System** shall withstand transient faults on HVAC lines in the network adjacent or close to the **HVDC System**, and shall not cause any of the equipment in the **HVDC System** to disconnect from the network due to autoreclosure of lines in the **System**.

6.3.15.11.4 The **HVDC System Owner** shall provide information to **NGET** on the resilience of the **HVDC System** to AC **System** disturbances.

ECC.6.3.16 FAST FAULT CURRENT INJECTION

ECC.6.3.16.1 General Fast Fault Current injection, principles and concepts applicable to Type B, Type C and Type D Power Park Modules and HVDC Equipment

ECC.6.3.16.1.1 Each **Type B**, **Type C** and **Type D Power Park Module** or **HVDC Equipment** shall be required to satisfy the following requirements.

ECC.6.3.16.1.2 For any balanced or unbalanced fault which results in the phase voltage on one or more phases falling outside the limits specified in ECC.6.1.2 at the **Grid Entry Point** or **User System Entry Point**, each **Type B**, **Type C** and **Type D Power Park Module** or **HVDC Equipment** shall, unless otherwise agreed with **NGET**, be required to inject a reactive current above the shaded area shown in Figure ECC.16.3.16(a) and Figure 16.3.16(b). For the purposes of this requirement, the maximum rated current is taken to be the maximum current each Power Park Module (or constituent **Power Park Unit**) or **HVDC Converter** is capable of supplying when operating at rated **Active Power** and rated **Reactive Power** (as required under ECC.6.3.2) at a nominal voltage of 1.0pu. For example, in the case of a 100MW **Power Park Module** the **Rated Active Power** would be taken as 100MW and the rated **Reactive Power** would be taken as 32.8MVArs (ie **Rated MW** output operating at 0.95 **Power Factor** lead or 0.95 **Power Factor** lag as required under ECC.6.3.2.4). For the avoidance of doubt, where the phase voltage at the **Grid Entry Point** or **User System Entry Point** is not zero, the reactive current injected shall be in proportion to the retained voltage at the **Grid Entry Point** or **User System Entry Point** but shall still be required to remain above the shaded area in Figure 16.3.16(a) and Figure 16.3.16(b). .

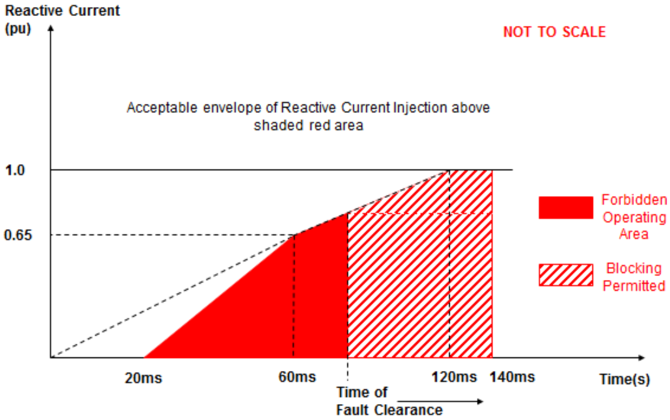


Figure ECC.16.3.16(a)

Figure ECC.16.3.16(b)

ECC.6.3.16.1.3 The converter(s) of each **Type B**, **Type C** and **Type D Power Park Module** or **HVDC Equipment** is permitted to block upon fault clearance in order to mitigate against the risk of instability that would otherwise occur due to transient overvoltage excursions. Figure ECC.16.3.16(a) and Figure ECC.16.3.16(b) shows the impact of variations in fault clearance time which shall be no greater than 140ms. The requirements for the maximum transient overvoltage withstand capability and associated time duration, shall be agreed between the **EU Code User** and **NGET** as part of the **Bilateral Agreement**. Where the **EU Code User** is able to demonstrate to **NGET** that blocking is required in order to prevent the risk of transient over voltage excursions as specified in ECC.6.3.16.1.5. **EU Generators** and **HVDC System Owners** are required to both advise and agree with **NGET** of the control strategy, which must also include the approach taken to de-blocking. Notwithstanding this requirement, **EU Generators** and **HVDC System Owners** should be aware of their requirement to fully satisfy the fault ride through requirements specified in ECC.6.3.15.

ECC.6.3.16.1.4 In addition, the reactive current injected from each **Power Park Module** or **HVDC Equipment** shall be injected in proportion and remain in phase to the change in **System** voltage at the **Connection Point** or **User System Entry Point** during the period of the fault. For the avoidance of doubt, a small delay time of no greater than 20ms from the point of fault inception is permitted before injection of the in phase reactive current.

ECC.6.3.16.1.5 Each **Type B**, **Type C** and **Type D Power Park Module** or **HVDC Equipment** shall be designed to reduce the risk of transient over voltage levels arising following clearance of the fault. **EU Generators** or **HVDC System Owners** shall be permitted to block where the anticipated transient overvoltage would otherwise exceed the maximum permitted values specified in ECC.6.1.7. Any additional requirements relating to transient overvoltage performance will be specified by **NGET**.

ECC.6.3.16.1.6 In addition to the requirements of ECC.6.3.15, **Generators** in respect of **Type B**, **Type C** and **Type D Power Park Modules** and **HVDC System Owners** are required to confirm to **NGET,** their repeated ability to supply **Fast Fault Current** to the **System** each time the voltage at the **Grid Entry Point** or **User System Entry Point** falls outside the limits specified in ECC.6.1.4. **EU Generators** and **HVDC Equipment Owners** should inform **NGET** of the maximum number of repeated operations that can be performed under such conditions and any limiting factors to repeated operation such as protection or thermal rating; and

ECC.6.3.16.1.7 In the case of a **Power Park Module** or **DC Connected Power Park Module**, where it is not practical to demonstrate the compliance requirements of ECC.6.3.16.1.1 to ECC.6.3.16.1.6 at the **Grid Entry Point** or **User System Entry Point**, **NGET** will accept compliance of the above requirements at the **Power Park Unit** terminals.

ECC.6.3.16.1.8 An illustration and examples of the performance requirements expected are illustrated in Appendix 4EC.

ECC.6.3.17 <u>SUBSYNCHRONOUS TORSIONAL INTERACTION DAMPING CAPABILITY, POWER OSCILLATION DAMPING CAPABILITY AND CONTROL FACILITIES FOR HVDC SYSTEMS</u>

ECC.6.3.17.1 Subsynchronous Torsional Interaction Damping Capability

ECC.6.3.17.1.1 **HVDC System Owners**, or **Generators** in respect of **OTSDUW DC Converters** or **Network Operators** in the case of an **Embedded HVDC Systems** not subject to a **Bilateral Agreement** must ensure that any of their **Onshore HVDC Systems** or **OTSDUW DC Converters** will not cause a sub-synchronous resonance problem on the **Total System**. Each **HVDC System** or **OTSDUW DC Converter** is required to be provided with sub-synchronous resonance damping control facilities. **HVDC System Owners** and **EU Generators** in respect of **OTSDUW DC Converters** should also be aware of the requirements in ECC.6.1.9 and ECC.6.1.10.

ECC.6.3.17.1.2 Where specified in the **Bilateral Agreement**, each **OTSDUW DC Converter** is required to be provided with power oscillation damping or any other identified additional control facilities.

ECC.6.3.17.1.3 Each **HVDC System** shall be capable of contributing to the damping of power oscillations on the **National Electricity Transmission System**. . The control system of the **HVDC System** shall not reduce the damping of power oscillations. **NGET** in coordination with the **Relevant Transmission Licensee** (as applicable)shall specify a frequency range of oscillations that the control scheme shall positively damp and the **System** conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by the **Relevant Transmission Licensee** or **NGET** (as applicable) to identify the stability limits and potential stability problems on the **National Electricity Transmission System**. The selection of the control parameter settings shall be agreed between **NGET** in coordination with the **Relevant Transmission Licensee** and the **HVDC System Owner**.

ECC.6.3.17.1.4 **NGET** shall specify the necessary extent of SSTI studies and provide input parameters, to the extent available, related to the equipment and relevant system conditions on the **National Electricity Transmission System**. The SSTI studies shall be provided by the **HVDC System Owner**. The studies shall identify the conditions, if any, where SSTI exists and propose any necessary mitigation procedure. The responsibility for undertaking the studies in accordance with these requirements lies with the **Relevant Transmission Licensee** in co-ordiantion with **NGET**. All parties shall be informed of the results of the studies.

ECC.6.3.17.1.5 All parties identified by **NGET** as relevant to each **Grid Entry Point** or **User System Entry Point** (if **Embedded**) , including the **Relevant Transmission Licensee**, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. **NGET** shall collect this data and, where applicable, pass it on to the party responsible for the studies in accordance with Article 10 of **European Regulation 2016/1447**. Specific information relating to the interface schedules, input/output requirements, timing and submission of any studies or data would be agreed between the **User** and **NGET** and specified (where applicable) in the **Bilateral Agreement**.

ECC.6.3.17.1.6 **NGET** in coordination with the **Relevant Transmission Licensee** shall assess the result of the SSTI studies. If necessary for the assessment, **NGET** in coordination with the **R**elevant **Transmission Licensee** may request that the **HVDC System Owner** perform further SSTI studies in line with this same scope and extent.

ECC.6.3.17.1.7 **NGET** in coordination with the **Relevant Transmission Licensee** may review or replicate the study. The **HVDC System Owner** shall provide **NGET** with all relevant data and models that allow such studies to be performed. Submission of this data to **Relevant Transmission Licensee's** shall be in accordance with the requirements of Article 10 of **European Regulation** 2016/1447.

ECC.6.3.17.1.8 Any necessary mitigating actions identified by the studies carried out in accordance with paragraphs ECC.6.3.17.1.4 or ECC.6.3.17.1.6, and reviewed by **NGET** in coordination with the **Relevant Transmission Licensees**, shall be undertaken by the **HVDC System Owner** as part of the connection of the new **HVDC Converter Station**.

ECC.6.3.17.1.9 As part of the studies and data flow in respect of ECC.6.3.17.1 – ECC.6.3.17.8 the following data exchange would take place with the time scales being pursuant to the terms of the Bilateral Agreement.

Information supplied by **NGET** and **Relevant Transmission Licensees**

Studies provided by the **User**

User review

NGET review

Changes to studies and agreed updates between **NGET**, the **Relevant Transmission Licensee** and **User**

Final review

ECC.6.3.17.2 Interaction between **HVDC Systems** or other **User's Plant** and **Apparatus**

ECC.6.3.17.2.1 Notwithstanding the requirements of ECC6.1.9 and ECC.6.1.10, when several **HVDC Converter Stations** or other **User's Plant** and **Apparatus** are within close electrical proximity, **NGET** ~~the relevant TSO~~ may specify that a study is required, and the scope and extent of that study, to demonstrate that no adverse interaction will occur. If adverse interaction is identified, the studies shall identify possible mitigating actions to be implemented to ensure compliance with the requirements of ECC.6.1.9

ECC.6.3.17.2.2 The studies shall be carried out by the connecting **HVDC System Owner** with the participation of all other **User's** identified by **NGET** in coordination with **Relevant Transmission Licensees** ~~the TSOs~~ as relevant to each **Connection Point**.

ECC.6.3.17.2.3 All **User's** identified by **NGET** as relevant to the connection , and where applicable ~~the~~ **Relevant Transmission Licensee's** ~~TSO~~, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. **NGET** shall collect this input and, where applicable, pass it on to the party responsible for the studies in accordance with Article 10 of **European Regulation 2016/1447**. Specific information relating to the interface schedules, input/output requirements, timing and submission of any studies or data would be agreed between the **User** and **NGET** and specified (where applicable) in the **Bilateral Agreement.**

ECC.6.3.17.2.4 **NGET** in coordination with **Relevant Transmission Licensees** shall assess the result of the studies based on their scope and extent as specified in accordance with ECC.6.3.17.2.1. If necessary for the assessment, **NGET** in coordination with the **Relevant Transmission Licensee** may request the **HVDC System Owner** to perform further studies in line with the scope and extent specified in accordance with ECC.6.3.17.2.1.

ECC.6.3.17.2.5 **NGET** in coordination with the **Relevant Transmission Licensee** may review or replicate some or all of the studies. The **HVDC System Owner** shall provide **NGET** all relevant data and models that allow such studies to be performed.

ECC.6.3.17.2.6 The **EU Code User** and **NGET,** in coordination with the **Relevant Transmission Licensee,** shall agree any mitigating actions identified by the studies carried out following the site specific requirements and works, including any transmission reinforcement works and / or **User** works required to ensure that all sub-synchronous oscillations are sufficiently damped.

ECC.6.1.17.3 Fast Recovery from DC faults

ECC.6.1.17.3.1 **HVDC Systems**, including DC overhead lines, shall be capable of fast recovery from transient faults within the **HVDC System**. Details of this capability shall be subject to the **Bilateral Agreement** and the protection requirements specified in ECC.6.2.2 .

ECC.6.1.17.4 Maximum loss of **Active Power**

ECC.6.1.14.4.1 An **HVDC System** shall be configured in such a way that its loss of **Active Power** injection in the **GB Synchronous Area** shall be in accordance with the requirements of the **SQSS**.

ECC.6.3.18 SYSTEM TO GENERATOR OPERATIONAL INTERTRIPPING SCHEMES

ECC.6.3.18.1 **NGET** may require that a **System to Generator Operational Intertripping Scheme** be installed as part of a condition of the connection of the **EU Generator**. Scheme specific details shall be included in the relevant **Bilateral Agreement** and shall, 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 **Power Generating Module** to be either permanently armed or that can be instructed to be armed in accordance with BC2.8;

(3) the time within which the **Power Generating Module** 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 **Power Generating Module**.

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.

ECC.6.3.18.2 The time within which the **Power Generating Module(s)** circuit breaker(s) need to be automatically tripped is determined by the specific conditions local to the **EU Generator**. This 'time to trip' (defined as the 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 **Power Generating Module(s)** output prior to the automatic tripping of the **Power Generating 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.

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

ECC.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

ECC.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 ECC.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

ECC.6.4.3 As explained under **OC6**, each **Network Operator** and **Non Embedded Customer**, will make arrangements that will facilitate automatic low **Frequency Disconnection** of **Demand** (based on **Annual ACS Conditions**). ECC.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

ECC.6.4.4 Where **NGET** can reasonably demonstrate that an **Embedded Medium Power Station** or **Embedded HVDC System** 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 HVDC System** is situated to ensure that the operational metering equipment described in ECC.6.5.6 is installed such that **NGET** can receive the data referred to in ECC.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 ECC.6.5.6 is provided to **NGET**.

ECC.6.5 Communications Plant

ECC.6.5.1 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.

ECC.6.5.2 Control Telephony and System Telephony

ECC.6.5.2.1 **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**.

ECC.6.5.2.2 **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**.

ECC.6.5.2.3 Calls made and received over **Control Telephony** and **System Telephony** may be recorded and subsequently replayed for commercial and operational reasons.

ECC.6.5.3 Supervisory Tones

ECC.6.5.3.1 **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.

ECC.6.5.3.2 **System Telephony** supervisory tones indicate to the calling and receiving parties dial, engaged and ringing tones.

ECC.6.5.4 Obligations in respect of Control Telephony and System Telephony

ECC.6.5.4.1 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 HVDC Systems**. **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**.

ECC.6.5.4.2 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.

ECC.6.5.4.3 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**.

ECC.6.5.4.4 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.

ECC.6.5.4.5 **Control Telephony** and **System Telephony** shall only be used for the purposes of operational voice communication between **NGET** and the relevant **User**.

ECC.6.5.4.6 **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.

ECC.6.5.5 Technical Requirements for Control Telephony and System Telephony

ECC.6.5.5.1 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**.

ECC.6.5.5.2 **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.

ECC.6.5.6 Operational Metering

ECC.6.5.6.1 It is an essential requirement for **NGET** and **Network Operators** to have visibility of the real time output and status of indications of **User's Plant and Apparatus** so they can control the operation of the **System**.

ECC.6.5.6.2 **Type B**, **Type C** and **Type D Power Park Modules**, **HVDC Equipment**, **Network Operators** and **Non Embedded Customers** are required to be capable of exchanging operational metering data with **NGET** and **Relevant Transmission Licensees** (as applicable) with time stamping. Time stamping would generally be to a sampling rate of 1 second or better unless otherwisespecified by **NGET** in the **Bilateral Agreement**.

ECC.6.5.6.3 **NGET** in coordination with the **Relevant Transmission Licensee** shall specify in the **Bilateral Agreement** the operational metering signals to be provided by the **EU Generator**, **HVDC System Owner**, **Network Operator** or **Non-Embedded Customer**. In the case of **Network Operators** and **Non-Embedded Customers** detailed specifications relating to the operational metering standards and the data required are published as **Electrical Standards** in the Annex to the **General Conditions**.

6.5.6.4 (a) **NGET** shall provide system control and data acquisition (SCADA) outstation interface equipment., each **EU Code 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** from **Type B**, **Type C** and **Type D Power Generating Modules**, 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.

-(i~~ii~~) For **Type B**, **Type C** and **Type D Power Park Modules** 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 ECC.6.5.6.4(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**. 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 ECC.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**.

ECC.6.5.6.5 In addition to the requirements of the **Balancing Codes**, each **HVDC Converter** unit of an **HVDC system** shall be equipped with an automatic controller capable of receiving instructions from **NGET**. This automatic controller shall be capable of operating the **HVDC Converter** units of the **HVDC System** in a coordinated way. **NGET** shall specify the automatic controller hierarchy per **HVDC Converter** unit.

ECC.6.5.6.6 The automatic controller of the **HVDC System** referred to in paragraph ECC.6.5.6.5 shall be capable of sending the following signal types to **NGET** (where applicable) :

(a) operational metering signals, providing at least the following:

(i) start-up signals;

(ii) AC and DC voltage measurements;

(iii) AC and DC current measurements;

(iv) **Active** and **Reactive Power** measurements on the AC side;

(v) DC power measurements;

(vi) **HVDC Converter** unit level operation in a multi-pole type **HVDC Converter**;

(vii) elements and topology status; and

(viii) **Frequency Sensitive Mode**, **Limited Frequency Sensitive Mode Overfrequency** and **Limited Frequency Sensitive Mode Underfrequency Active Power** ranges (where applicable).

(b) alarm signals, providing at least the following:

(i) emergency blocking;

(ii) ramp blocking;

(iii) fast **Active Power** reversal (where applicable)

ECC.6.5.6.7 The automatic controller referred to in ECC.6.5.6.5 shall be capable of receiving the following signal types from **NGET** (where applicable) :

(a) operational metering signals, receiving at least the following:

(i) start-up command;

(ii) **Active Power** setpoints;

(iii) **Frequency Sensitive Mode** settings;

(iv) **Reactive Power**, voltage or similar setpoints;

(v) **Reactive Power** control modes;

(vi) power oscillation damping control; and

(b) alarm signals, receiving at least the following:

(i) emergency blocking command;

(ii) ramp blocking command;

(iii) **Active Power** flow direction; and

(iv)) fast **Active Power** reversal command.

ECC.6.5.6.8 With regard~~s~~ to operational metering signals, the resolution and refresh rate required would be 1 second or better unless otherwise agreed with **NGET**

Instructor Facilities

ECC.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

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**;

or

(2) any **BM Participant** in respect of its **BM Units** at a **Power Station** and the **BM Participant** is required to provide all **Part 1 System Ancillary Services** in accordance with ECC.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

ECC.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 **HVDC Equipment** 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.

ECC.6.5.10 Busbar Voltage

NGET shall, subject as provided below, provide each **Generator** or **HVDC System Owner** at each **Grid Entry Point** where one of its **Power Stations** or **HVDC Systems** is connected with appropriate voltage signals to enable the **Generator** or **HVDC System** owner to obtain the necessary information to permit its **Power Generating Modules** (including **DC Connected Power Park Modules**) or **HVDC System** 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 **HVDC System 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.

ECC.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.

ECC.6.6 Monitoring

ECC.6.6.1 System Monitoring

ECC.6.6.1.1 Each **Type C** and **Type D Power Generating Module** including **DC Connected Power Park Modules** shall be equipped with a facility to provide fault recording and monitoring of dynamic system behaviour. These requirements are necessary to record conditions during **System** faults and detect poorly damped power oscillations. This facility shall record the following parameters:

— voltage,

— **Active Power**,

— **Reactive Power**, and

— **Frequency**.

ECC.6.6.1.2 Detailed specifications for fault recording and dynamic system monitoring equipment including triggering criteria and sample rates are listed as **Electrical Standards** in the **Annex** to the **General Conditions**. For Dynamic System Monitoring, the specification for the communication protocol and recorded data shall also be included in the **Electrical Standard**.

ECC.6.6.1.3 **NGET** in coordination with the **Relevant Transmission Licensee** shall specify any requirements for **Power Quality Monitoring** in the **Bilateral Agreement**. The power quality parameters to be monitored, the communication protocols for the recorded data and the time frames for compliance shall be agreed between **NGET**, the **Relevant Transmission Licensee** and **EU Generator**.

ECC.6.6.1.4 **HVDC Systems** shall be equipped with a facility to provide fault recording and dynamic system behaviour monitoring of the following parameters for each of its **HVDC Converter Stations**:

(a) AC and DC voltage;

(b) AC and DC current;

(c) **Active Power**;

(d) **Reactive Power**; and

(e) **Frequency**.

ECC.6.6.1.5 **NGET** in coordination with the **Relevant Transmission Licensee** may specify quality of supply parameters to be complied with by the **HVDC System**, provided a reasonable prior notice is given.

ECC.6.6.1.6 The particulars of the fault recording equipment referred to in ECC.6.6.1.4, including analogue and digital channels, the settings, including triggering criteria and the sampling rates, shall be agreed between the **HVDC System Owner** and **NGET** in coordination with the **Relevant Transmission Licensee**.

ECC.6.6.1.7 All dynamic system behaviour monitoring equipment shall include an oscillation trigger, specified by **NGET**, in coordination with the **Relevant Transmission Licensee**, with the purpose of detecting poorly damped power oscillations.

ECC.6.6.1.8 The facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the **HVDC System Owner** and **NGET** and/or **Relevant Transmission Licensee** to access the information electronically. The communications protocols for recorded data shall be agreed between the **HVDC System Owner**, **NGET** and the **Relevant Transmission Licensee**.

ECC.6.6.2 Frequency Response Monitoring

ECC.6.6.2.1 Each **Type C** and **Type D Power Generating Module** including **DC Connected Power Park Modules** shall be fitted with equipment capable of monitoring the real time **Active Power** output of a **Power Generating Module** when operating in **Frequency Sensitive Mode**.

ECC.6.6.2.2

Detailed specifications of the **Active Power Frequency** response requirements including the communication requirements are listed as **Electrical Standards** in the **Annex** to the **General Conditions**.

ECC.6.6.2.3 **NGET** in co-ordination with the **Relevant Transmission Licensee** shall specify additional signals to be provided by the **EU Generator** by monitoring and recording devices in order to verify the performance of the **Active Power Frequency** response provision of participating **Power Generating Modules**.

ECC.6.6.3 Compliance Monitoring

ECC.6.6.3.1 For all on site monitoring by **NGET** of witnessed tests pursuant to the **CP** or **OC5** or **ECP** the **User** shall provide suitable test signals as outlined in either OC5.A.1or **ECP.A.4** (as applicable).

ECC.6.6.3.2 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

ECC.6.6.3.3 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 Generating Module** or **Onshore HVDC Convertor Station**~~,~~ be suitably terminated in a single accessible location at the **Generator** or **HVDC Converter Station** owner's site.

(ii) in the case of an **Offshore Power Generating 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.

ECC.6.6.3.4 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 **Maximum 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

ECC.6.6.3.5 The **User** shall provide to **NGET** a 230V power supply adjacent to the signal terminal location.

ECC.7 SITE RELATED CONDITIONS

ECC.7.1 Not used.

ECC.7.2 Responsibilities For Safety

ECC.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**.

ECC.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**.

ECC.7.2.3 A **User** may, with a minimum of six weeks notice, apply to **NGET** for permission to work according to that **Users** own **Safety Rules** when working on its **Plant** and/or **Apparatus** on a **Transmission Site** rather than those set out in ECC.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 ECC.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 ECC.7.2.1.

ECC.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**.

ECC.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 **Relevant Transmission Licensee** when working on its **Plant** and **Apparatus**, that does not imply that the **Relevant Transmission Licensee'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.

ECC.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**.

ECC.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**.

ECC.7.2.8 In the case of **OTSUA** a **User Site** or **Transmission Site** shall, for the purposes of this ECC.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**.

ECC.7.3 Site Responsibility Schedules

ECC.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.

ECC.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.

ECC.7.4 Operation And Gas Zone Diagrams

Operation Diagrams

ECC.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.

ECC.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**.

ECC.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

ECC.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.

ECC.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).

ECC.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

ECC.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**.

ECC.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** .

ECC.7.4.9 The provisions of ECC.7.4.7 and ECC.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

ECC.7.4.10 In the case of an **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**.

ECC.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** .

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

ECC.7.4.13 Changes to Operation and Gas Zone Diagrams

ECC.7.4.13.1 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**.

ECC.7.4.13.2 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 **EU Code 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**.

ECC.7.4.13.3 The provisions of ECC.7.4.13.1 and ECC.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

7.4.14 (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**.

ECC.7.4.15 In the case of **OTSUA**, a **User Site** and **Transmission Site** shall, for the purposes of this ECC.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 ECC.7.4 shall include references to **HV OTSUA**.

ECC.7.5 Site Common Drawings

ECC.7.5.1 **Site Common Drawings** will be prepared for each **Connection Site** (and in the case of **OTSDUW**, each **Interface Point**) and will include **Connection Site** (and in the case of **OTSDUW**, **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

ECC.7.5.2 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 **OTSDUW 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 **OTSDUW**, 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**.

ECC.7.5.3 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

ECC.7.5.4 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**.

ECC.7.5.5 **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**.

ECC.7.5.6 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.

ECC.7.5.7 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** (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

7.5.8 (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.

ECC.7.5.9 In the case of **OTSUA**, a **User Site** and **Transmission Site** shall, for the purposes of this ECC.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**.

ECC.7.6 Access

ECC.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**.

ECC.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**.

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

ECC.7.7 Maintenance Standards

ECC.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

ECC.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.

ECC.7.8 Site Operational Procedures

ECC.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**.

ECC.7.9 **Generators** and **HVDC System** 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 **HVDC System** to receive and act upon instructions pursuant to OC7 and BC2 at all times that **Power Generating Modules** at the **Power Station** are generating or available to generate or **HVDC Systems** 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.

ECC.8 ANCILLARY SERVICES

ECC.8.1 System Ancillary Services

The **ECC** 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 **ECC** (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 **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) are obliged to provide; and,

-(b) **HVDC System Owners** are obliged to have the capability to supply;

(c) **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 ECC.6.3.2)

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

Part 2

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

(d) **Black Start Capability** - ECC.6.3.5

(e) **System to Generator Operational Intertripping**

ECC.8.2 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 E1 - SITE RESPONSIBILITY SCHEDULES

<u>FORMAT, PRINCIPLES AND BASIC PROCEDURE TO BE USED IN THE PREPARATION OF SITE RESPONSIBILITY SCHEDULES</u>

ECC.A.1.1 <u>Principles</u>

<u>Types of Schedules</u>

ECC.A.1.1.1 At all **Complexes** (which in the context of this ECC 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 **Power Generating Module** (including **DC Connected Power Park Modules**) and **Power Station** locations, the schedules referred to in (b) and (c) may be combined.

<u>New Connection Sites</u>

ECC.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 **ECC** 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**.

<u>Sub-division</u>

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

<u>Scope</u>

ECC.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

A.1.1.5 (a) In the case of **Site Responsibility Schedules** referred to in ECC.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 ECC.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.

ECC.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

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

Accuracy Confirmation

ECC.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.

ECC.A.1.1.9 The **Site Responsibility Schedule** shall then be signed on behalf of **NGET** by its **Responsible Manager** (see ECC.A.1.1.16) and on behalf of each **User** involved by its **Responsible Manager** (see ECC.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

ECC.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.

ECC.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

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 15th October 2004. In Scotland or **Offshore**, from a date to be agreed between **NGET** and **the Relevant Transmission Licensee**.

ECC.A 1.1.12 Without prejudice to the provisions of ECC.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**.

ECC.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 ECC.A.1.1.8 shall be followed with regard to the revised **Site Responsibility Schedule**.

ECC.A 1.1.14 The revised **Site Responsibility Schedule** shall then be signed in accordance with the procedure set out in ECC.A.1.1.9 and distributed in accordance with the procedure set out in ECC.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.

Urgent Changes

ECC.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 ECC.A.1.1.9) as soon as possible after it has been prepared and sent to **Users** for confirmation.

Responsible Managers

ECC.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

ECC.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: ______________________

ITEM OF PLANT/ APPARATUS	PLANT APPARATUS OWNER	SITE MANAGER	SAFETY		OPERATIONS		PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION & MAINTENANCE	REMARKS
			SAFETY RULES	CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY CO-ORDINATOR	OPERATIONAL PROCEDURES	CONTROL OR OTHER RESPONSIBLE ENGINEER		

PAGE: ______________ ISSUE NO: ____________________ DATE: ______________________

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

AREA ______________________

COMPLEX: ______________________ SCHEDULE: ______________________

CONNECTION SITE: ______________________

ITEM OF PLANT/ APPARATUS	PLANT APPARATUS OWNER	SITE MANAGER	SAFETY		OPERATIONS		PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION & MAINTENANCE	REMARKS
			SAFETY RULES	CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY CO-ORDINATOR	OPERATIONAL PROCEDURES	CONTROL OR OTHER RESPONSIBLE ENGINEER		

NOTES:

SIGNED: ______________ NAME: ______________ COMPANY: ______________ DATE: ______________

SIGNED: ______________ NAME: ______________ COMPANY: ______________ DATE: ______________

SIGNED: ______________ NAME: ______________ COMPANY: ______________ DATE: ______________

SIGNED: ______________ NAME: ______________ COMPANY: ______________ DATE: ______________

PAGE: ______________ ISSUE NO: ______________ DATE: ______________

SP TRANSMISSION Ltd
SITE RESPONSIBILITY SCHEDULE
OWNERSHIP, MAINTENANCE AND OPERATIONS OF EQUIPMENT
IN JOINT USER SITUATIONS

Network Area:

Sheet No.
Revision:
Date:

SECTION 'A' BUILDING AND SITE

OWNER		ACCESS REQUIRED:-	
LESSEE			
MAINTENANCE		SPECIAL CONDITIONS:-	
SAFETY			
SECURITY		LOCATION OF SUPPLY TERMINALS:-	

SECTION 'B' CUSTOMER OR OTHER PARTY

NAME:-	
ADDRESS:-	
TEL NO:-	
SUB STATION:-	
LOCATION:-	

SECTION 'C' PLANT

ITEM Nos.	EQUIPMENT	IDENTIFICATION	OWNER	SAFETY RULES APPLICABLE	OPERATION				MAINTENANCE		FAULT INVESTIGATION			TESTING		RELAY SETTINGS	REMARKS
					Tripping	Closing	Isolating	Earthing	Primary Equip.	Protection Equip.	Primary Equip.	Protection Equip.	Reclosure	Trip and Alarm	Primary Equip.		

SECTION 'D' CONFIGURATION AND CONTROL

ITEM Nos.	CONFIGURATION RESPONSIBILITY	TELEPHONE NUMBER	REMARKS
ITEM Nos.	CONTROL RESPONSIBILITY	TELEPHONE NUMBER	REMARKS

SECTION 'E' ADDITIONAL INFORMATION

ABBREVIATIONS:-
D - SP AUTHORISED PERSON - DISTRIBUTION SYSTEM
NGC - NATIONAL GRID COMPANY
SPD - SP DISTRIBUTION Ltd
SPPS - POWERSYSTEMS
SPT - SP TRANSMISSION Ltd
ST - SCOTTISH POWER TELECOMMUNICATIONS
T - SP AUTHORISED PERSON - TRANSMISSION SYSTEM
U - USER

SIGNED ______ FOR SP Transmission DATE ______

SIGNED ______ FOR SP Distribution DATE ______

SIGNED ______ FOR PowerSystems/User DATE ______

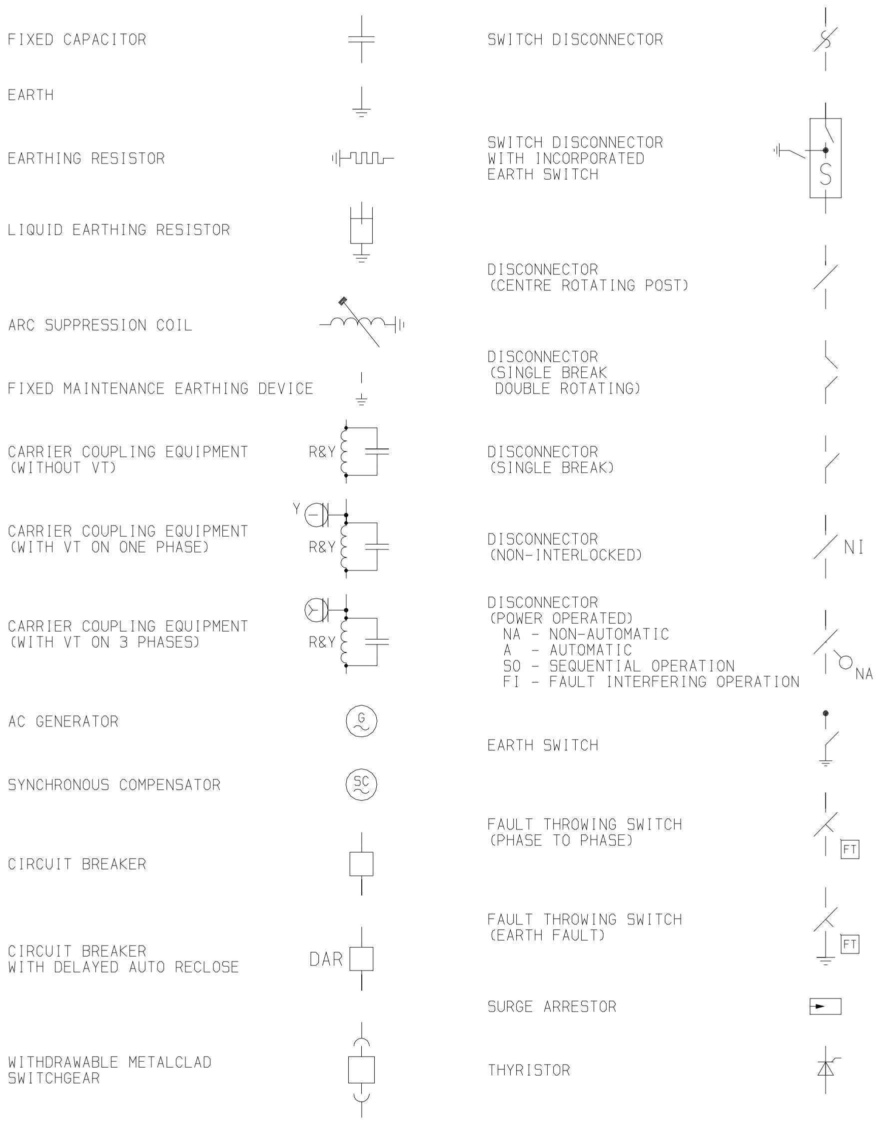
Scottish Hydro-Electric Transmission Limited

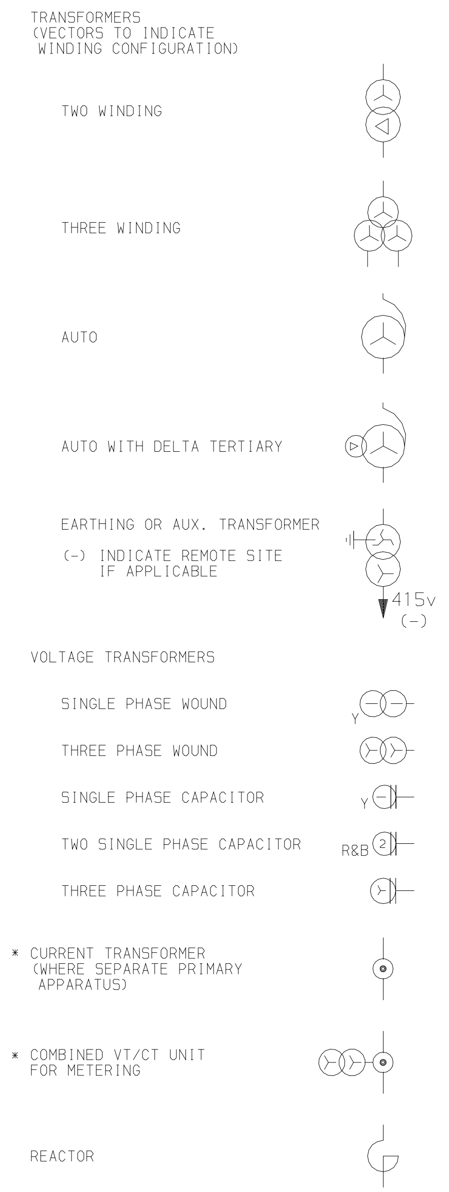
Site Responsibility Schedule

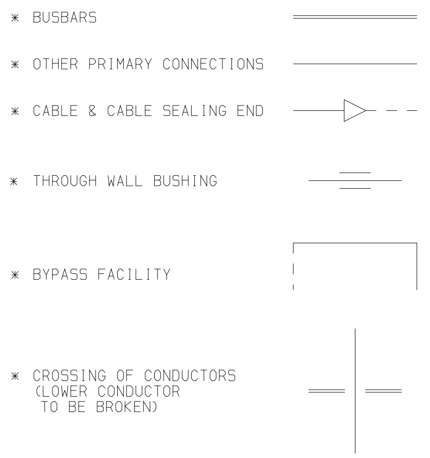
Substation Type				Number:			Revision:		
Equipment	**Owner**	**Controller**	**Maintainer**	**Responsible System User**	**Responsible Management Unit**	**Control Authority**	**Safety Rules**	**Operational Procedures**	**Notes**

APPENDIX E2 - OPERATION DIAGRAMS

PART 1A - PROCEDURES RELATING TO OPERATION DIAGRAMS





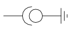


PREFERENTIAL ABBREVIATIONS

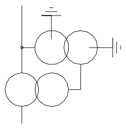
AUXILIARY TRANSFORMER	Aux T
EARTHING TRANSFORMER	ET
GAS TURBINE	Gas T
GENERATOR TRANSFORMER	Gen T
GRID TRANSFORMER	Gr T
SERIES REACTOR	Ser Reac
SHUNT REACTOR	Sh Reac
STATION TRANSFORMER	Stn T
SUPERGRID TRANSFORMER	SGT
UNIT TRANSFORMER	UT

* NON-STANDARD SYMBOL

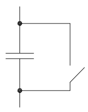
PORTABLE MAINTENANCE
EARTH DEVICE



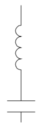
QUADRATURE BOOSTER



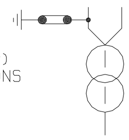
SHORTING/DISCHARGE SWITCH



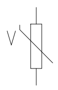
CAPACITOR
(INCLUDING HARMONIC FILTER)



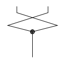
SINGLE PHASE TRANSFORMER(BR)
NEUTRAL AND PHASE CONNECTIONS



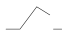
RESISTOR WITH INHERENT
NON-LINEAR VARIABILITY,
VOLTAGE DEPENDANT



DISCONNECTOR
(PANTOGRAPH TYPE)



DISCONNECTOR
(KNEE TYPE)



PART E1B - PROCEDURES RELATING TO GAS ZONE DIAGRAMS

PART E2 - 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

(22) Single Phase VT & Phase Identity

(23) High Accuracy VT and Phase Identity

(24) Surge Arrestors/Diverters

(25) Neutral Earthing Arrangements on HV Plant

(26) Fault Throwing Devices

(27) Quadrature Boosters

(28) Arc Suppression Coils

(29) Single Phase Transformers (BR) Neutral and Phase Connections

(30) Current Transformers (where separate plant items)

(31) Wall Bushings

(32) Combined VT/CT Units

(33) Shorting and Discharge Switches

(34) Thyristor

(35) Resistor with Inherent Non-Linear Variability, Voltage Dependent

(36) Gas Zone

APPENDIX E3 - MINIMUM FREQUENCY RESPONSE CAPABILITY REQUIREMENT PROFILE AND OPERATING RANGE FOR POWER GENERATING MODULES AND HVDC EQUIPMENT

ECC.A.3.1 Scope

The frequency response capability is defined in terms of **Primary Response**, **Secondary Response** and **High Frequency Response**. In addition to the requirements defined in ECC.6.3.7 this appendix defines the minimum frequency response requirements for:-

1. each **Type C** and **Type D Power Generating Module**
2. each **DC Connected Power Park Module**
3. each **HVDC System**

For the avoidance of doubt, this appendix does not apply to **Type A** and **Type B Power Generating Modules**.

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

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 ECC.6.3.7.

In this Appendix 3 to the E**CC**, for a **Power Generating Module** including a **CCGT Module** or a **Power Park Module** or **DC Connected Power Park Module**, the phrase **Minimum Regulating Level** applies to the entire **CCGT Module** or **Power Park Module** or **DC Connected Power Park Module** operating with all **Generating Units Synchronised** to the **System**.

The minimum **Frequency** response requirement profile is shown diagrammatically in Figure ECC.A.3.1. The capability profile specifies the minimum required level of **Frequency Response** Capability throughout the normal plant operating range.

ECC.A.3.2 Plant Operating Range

The upper limit of the operating range is the **Maximum Capacity** of the **Power Generating Module** or **Generating Unit** or **CCGT Module** or **HVDC Equipment**.

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

In the event of a **Power Generating Module** or **Generating Unit** or **CCGT Module** or **Power Park Module** or **HVDC Equipment** load rejecting down to no less than its **Minimum Regulating 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 **Minimum Regulating Level** then it is accepted that the condition might be so severe as to cause it to be disconnected from the **System**.

ECC.A.3.3 Minimum Frequency Response Requirement Profile

Figure ECC.A.3.1 shows the minimum **Frequency** response capability 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 **Maximum Capacity** of the **Power Generating Module** or **CCGT Module** or **Power Park Module** or **HVDC Equipment**. Each **Power Generating Module** or and/or **CCGT Module** or **Power Park Module** (including a **DC Connected Power Park Module**) and/or **HVDC Equipment** 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 **Power Generating Module** or **CCGT Module** or **Power Park Module** or **HVDC Equipment** is providing response below the minimum requirement which is not acceptable. Nothing in this appendix is intended to prevent a **Power Generating Module** or **CCGT Module** or **Power Park Module** or **HVDC Equipment** 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 ECC.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 **Power Generating Module** and/or **CCGT Module** and/or **Power Park Module** or **HVDC Equipment** must be capable of providing some response, in keeping with its specific operational characteristics, when operating between 95% to 100% of **Maximum Capacity** as illustrated by the dotted lines in Figure ECC.A.3.1.

At the **Minimum Stable Operating** level, each **Power Generating Module** and/or **CCGT Module** and/or **Power Park Module** and/or HV**DC Equipment** 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 Stable Operating** level.

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

ECC.A.3.4 Testing of Frequency Response Capability

The frequency response capabilities shown diagrammatically in Figure ECC.A.3.1 are measured by taking the responses as obtained from some of the dynamic step response tests specified by **NGET** and carried out by **Generators** and HV**DC System** owners for compliance purposes. The injected signal is a step of 0.5Hz from zero to 0.5 Hz **Frequency** change, and is sustained at 0.5 Hz **Frequency** change thereafter, the latter as illustrated diagrammatically in figures ECC.A.3.4 and ECC.A.3.5.

In addition to provide and/or to validate the content of **Ancillary Services Agreements** a progressive injection of a **Frequency** change to the plant control system (i.e. governor and load controller) is used. The injected signal is a ramp of 0.5Hz from zero to 0.5 Hz **Frequency** change over a ten second period, and is sustained at 0.5 Hz **Frequency** change thereafter, the latter as illustrated diagrammatically in figures ECC.A.3.2 and ECC.A.3.3. In the case of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded HVDC System** not subject to a **Bilateral Agreement**, **NGET** may require the **Network Operator** within whose System the **Embedded Medium Power Station** or **Embedded HVDC System** 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 **ECC**.

The **Primary Response** capability (P) of a **Power Generating Module** or a **CCGT Module** or **Power Park Module** or **HVDC Equipment** 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 ECC.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 ECC.A.3.2.

The **Secondary Response** capability (S) of a **Power Generating Module** or a **CCGT Module** or **Power Park Module** or **HVDC Equipment** 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 ECC.A.3.2.

The **High Frequency Response** capability (H) of a **Power Generating Module** or a **CCGT Module** or **Power Park Module** or **HVDC Equipment** 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 ECC.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 ECC.A.3.2.

ECC.A.3.5 Repeatability Of Response

When a **Power Generating Module** or **CCGT Module** or **Power Park Module** or **HVDC Equipment** 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 ECC.A.3.1 - Minimum **Frequency** Response requirement profile for a 0.5 Hz frequency change from **Target Frequency**

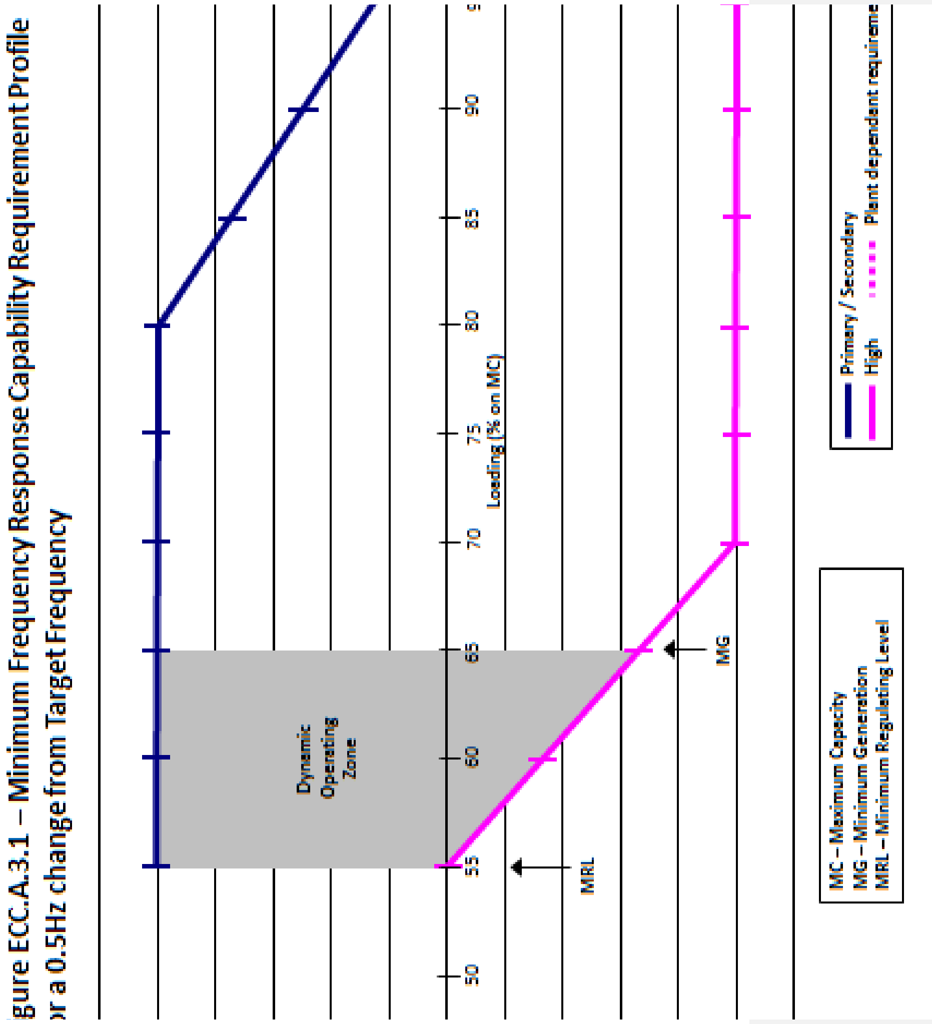


Figure ECC.A.3.2 – Interpretation of Primary and Secondary Response Service Values

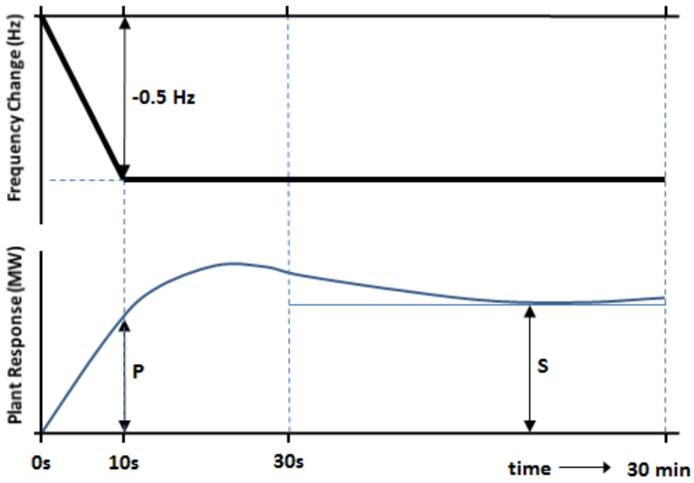


Figure ECC.A.3.3 – Interpretation of High Frequency Response Service Values

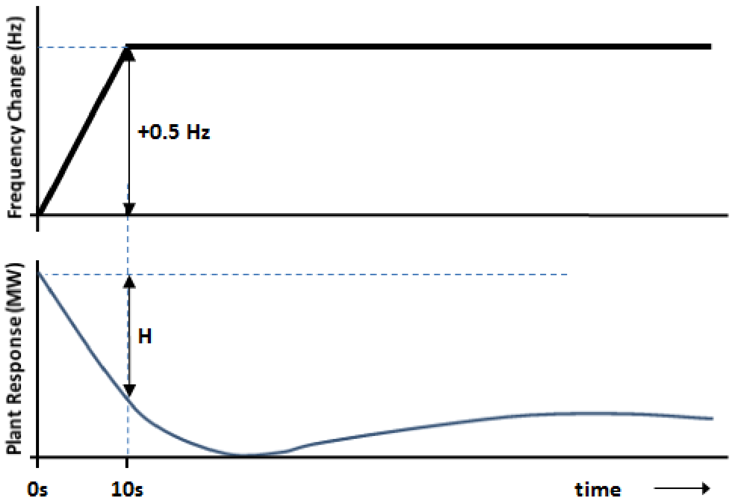


Figure ECC.A.3.4 – Interpretation of Low Frequency Response Capability Values

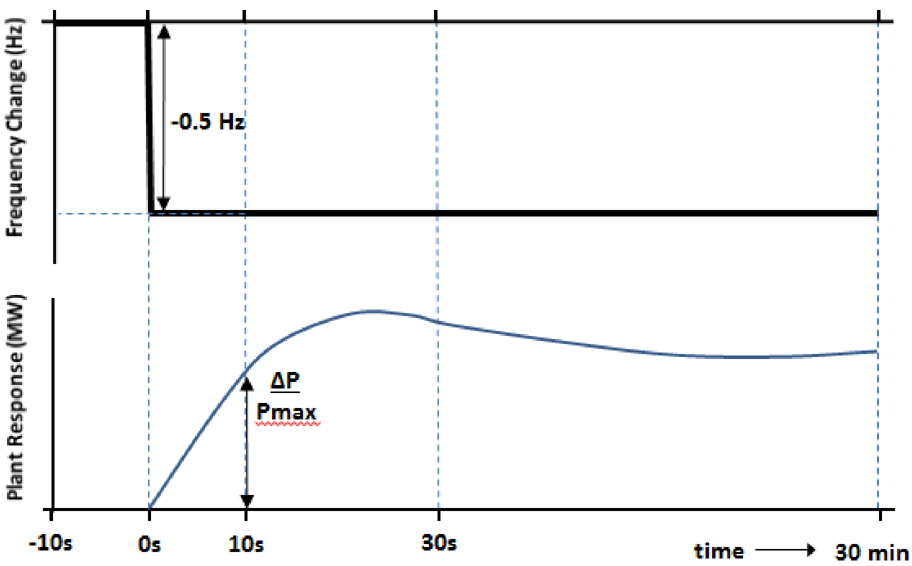
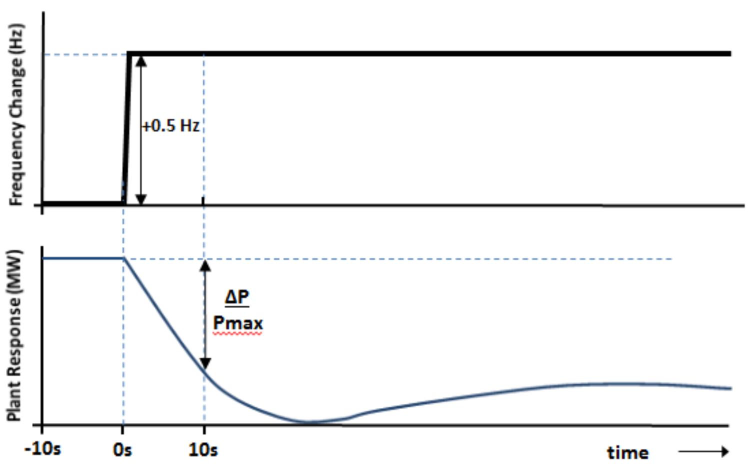


Figure ECC.A.3.5 – Interpretation of High Frequency Response Capability Values



ECC.4 - APPENDIX 4 - FAULT RIDE THROUGH REQUIREMENTS

FAULT RIDE THROUGH REQUIREMENTS FOR TYPE B, TYPE C AND TYPE D POWER GENERATING MODULES (INCLUDING OFFSHORE POWER PARK MODULES WHICH ARE EITHER AC CONNECTED POWER PARK MODULES OR DC CONNECTED POWER PARK MODULES), HVDC SYSTEMS AND OTSDUW PLANT AND APPARATUS

ECC.A.4A.1 Scope

The **Fault Ride Through** requirements are defined in ECC.6.3.15. This Appendix provides illustrations by way of examples only of ECC.6.3.15.1 to ECC.6.3.15.10 and further background and illustrations and is not intended to show all possible permutations.

ECC.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 ECC.6.3.15. In summary any **Power Generating Module** (including a **DC Connected Power Park Module**) or **HVDC System** is required to remain connected and stable whilst connected to a healthy circuit. Figure ECC.A.4.A.2 illustrates this principle.

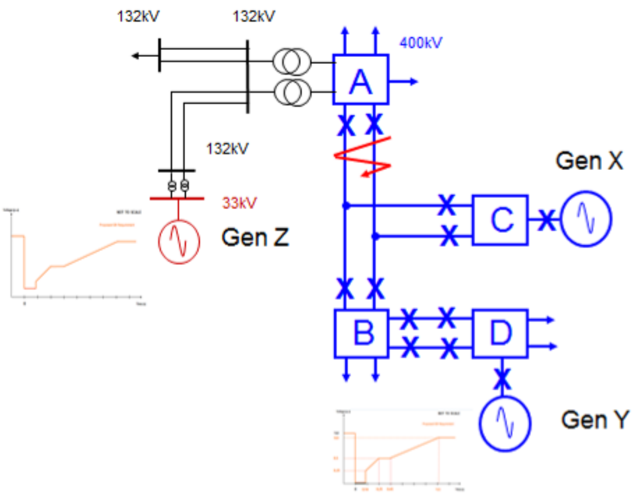


Figure ECC.A.4.A.2

In Figure ECC.A.4.A.2 a solid three phase short circuit fault is applied adjacent to substation A resulting in zero voltage at the point of fault. All circuit breakers on the faulty circuit (Lines ABC) will open within 140ms resulting in Gen X tripping. The effect of this fault, due to the low impedance of the network, will be the observation of a low voltage at each substation node across the **Total System** until the fault has been cleared. In this example, Gen Y and Gen Z (an Embedded Generator) would need to remain connected and stable as both are still connected to the **Total System** and remain connected to healthy circuits .

The criteria for assessment is based on a voltage against time curve at each **Grid Entry Point** or **User System Entry Point**. The voltage against time curve at the **Grid Entry Point** or **User System Entry Point** varies for each different type and size of **Power Generating Module** as detailed in ECC.6.3.15.2. – ECC.6.3.15.7.

The voltage against time curve represents the voltage profile at a **Grid Entry Point or User System Entry Point** that would be obtained by plotting the voltage at that **Grid Entry Point** or **User System Entry Point** before during and after the fault. This is not to be confused with a voltage duration curve (as defined under ECC.6.3.15.9) which represents a voltage level and associated time duration.

The post fault voltage at a **Grid Entry Point** or **User System Entry Point** is largely influenced by the topology of the network rather than the behaviour of the **Power Generating Module** itself. The **EU Generator** therefore needs to ensure each **Power Generating Module** remains connected and stable for a close up solid three phase short circuit fault for 140ms at the **Grid Entry Point** or **User System Entry Point**.

Two examples are shown in Figure EA.4.2(a) and Figure EA4.2(b). In Figure EA.4.2(a) the post fault profile is above the heavy black line. In this case the **Power Generating Module** must remain connected and stable. In Figure EA4.2(b) the post fault voltage dips below the heavy black line in which case the **Power Generating Module** is permitted to trip.

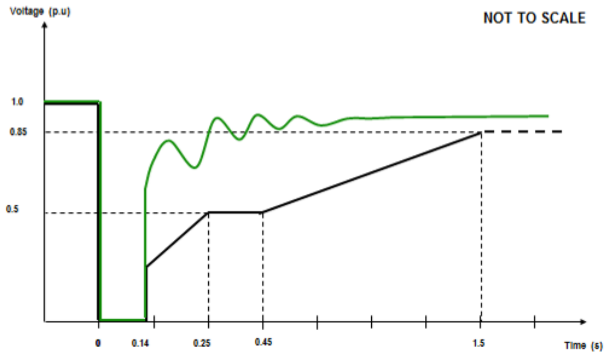


Figure EA.4.2(a)

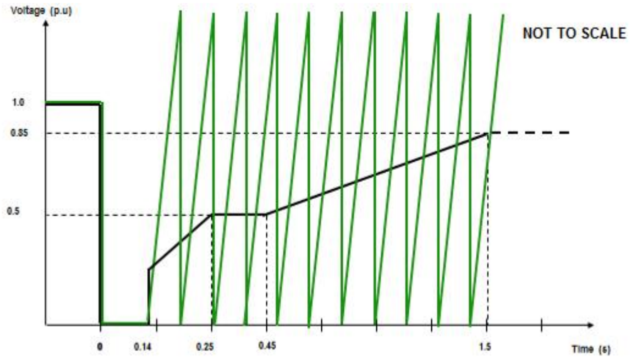


Figure EA.4.2(b)

The process for demonstrating **Fault Ride Through** compliance against the requirements of ECC.6.3.15 is detailed in ECP.A.3.5 and ECP.A.6.7 (as applicable).

ECC.A.4A.3 Supergrid Voltage Dips On The Onshore Transmission System Greater Than 140ms In Duration

ECC.A.4A3.1 Requirements applicable to **Synchronous Power Generating Modules** 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 ECC.6.3.15.9.2.1(a) and Figure ECC.6.3.15.9(a) which is reproduced in this Appendix as Figure EA.4.3.1 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 (ie the heavy black line) represents a voltage level and an associated time duration which connected **Synchronous Power Generating Modules** must withstand or ride through.

Figures EA.4.3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

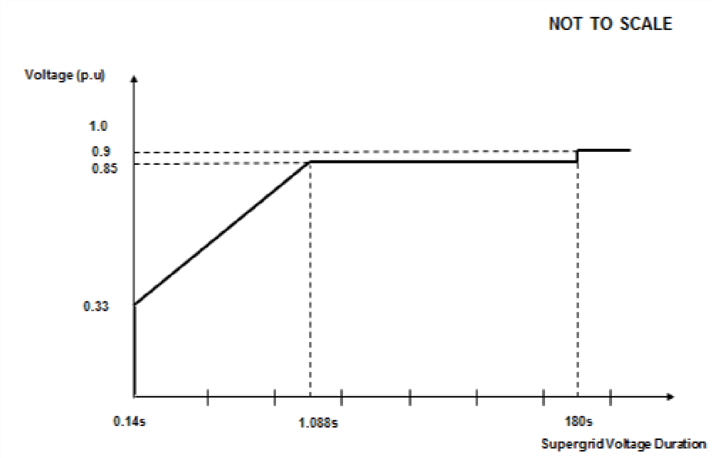


Figure EA.4.3.1

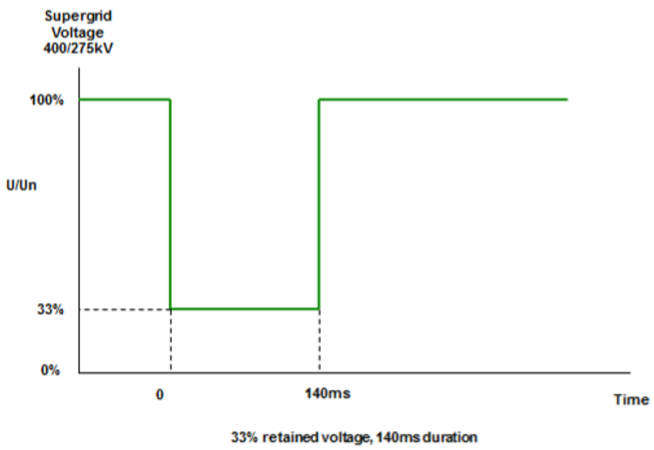


Figure EA.4.3.2 (a)

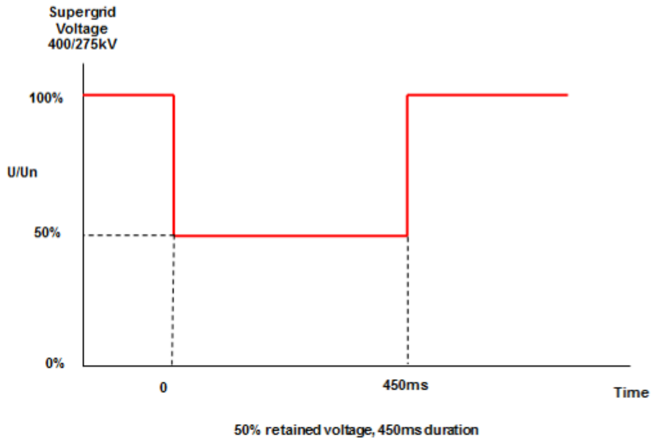


Figure EA.4.3.2 (b)

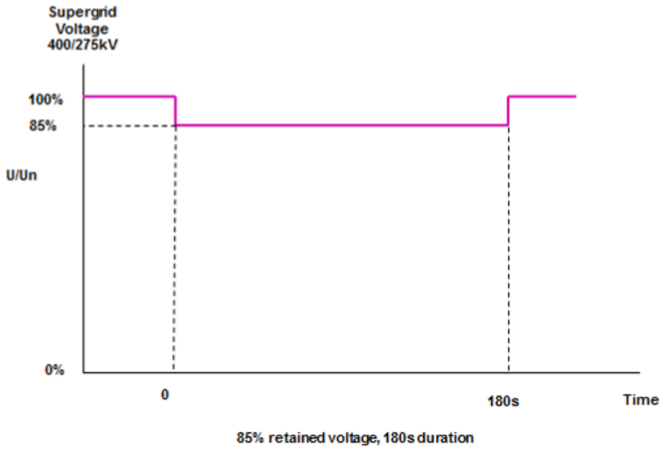


Figure EA.4.3.2 (c)

ECC.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 ECC.6.3.15.9.2.1(b) and Figure ECC.6.3.15.9(b) which is reproduced in this Appendix as Figure EA.4.3.3 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 (ie 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 EA.4.3.4 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

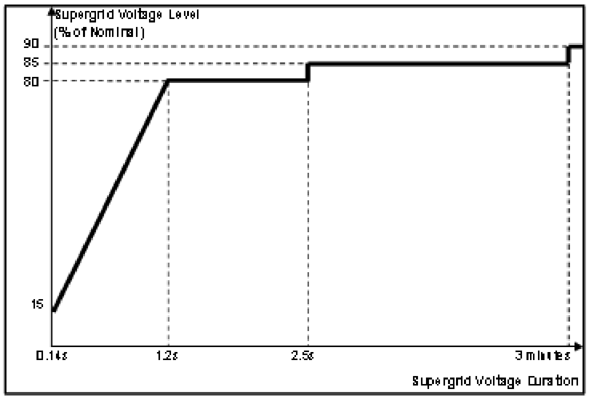


Figure EA.4.3.3

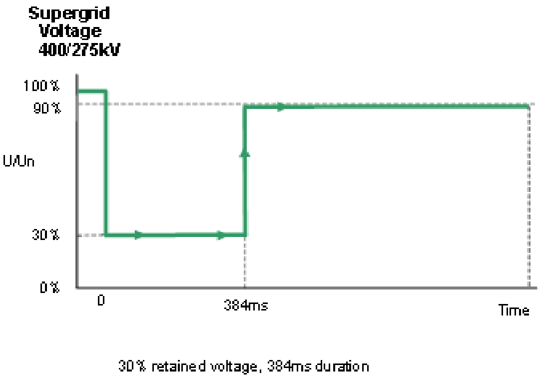
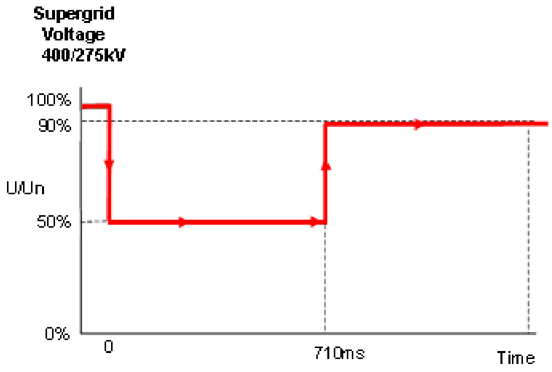
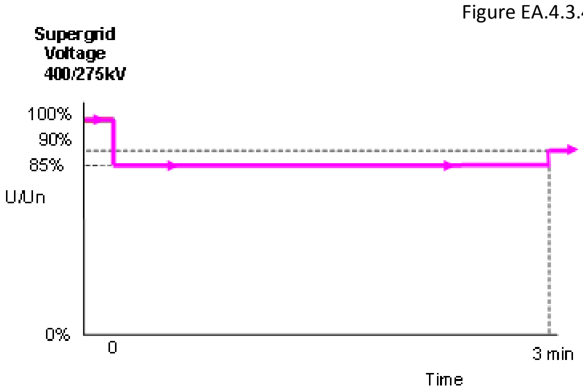


Figure EA.4.3.4(a)



50% retained voltage, 710ms duration

Figure EA.4.3.4 (b)



85% retained voltage, 3 minutes duration

Figure EA.4.3.4 (c)

APPENDIX 4EC – FAST FAULT CURRENT INJECTION REQUIREMENTS

FAST FAULT CURRENT INJECTION REQUIREMENTS FOR POWER PARK MODULES, HVDC SYSTEMS, DC CONNECTED POWER PARK MODULES AND REMOTE END HVDC CONVERTERS

ECC.A.4EC1 Fast Fault Current Injection requirements

ECC.4EC1.1 Fast Fault Current Injection behaviour during a solid three phase close up short circuit fault lasting up to 140ms

ECC.4EC1.1.1 For a voltage depression at a **Grid Entry Point or User System Point**, the **Fast Fault Current** Injection requirements are detailed in ECC.6.3.16. Figure ECC4.1 shows an example of a 500MW **Power Park Module** subject to a close up solid three phase short circuit fault connected directly connected to the **Transmission System** operating at 400kV.

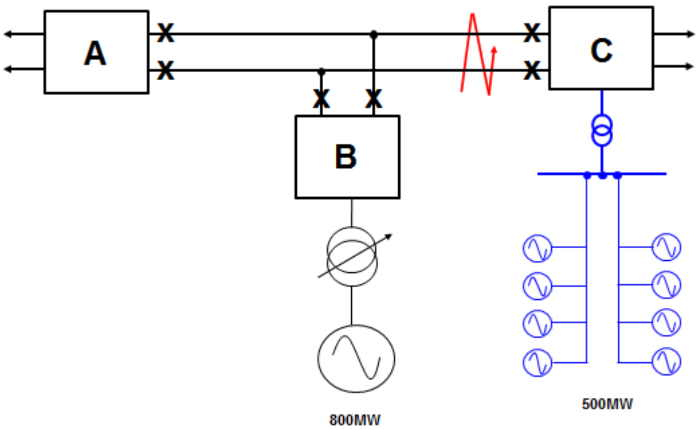


Figure ECC4.1

ECC.4EC1.1.2 Assuming negligible impedance between the fault and substation C, the voltage at Substation C will be close to zero until circuit breakers at Substation C open, typically within 80 – 100ms, subsequentially followed by the opening of circuit breakers at substations A and B, typically 140ms after fault inception. The operation of circuit breakers at Substations A, B and C will also result in the tripping of the 800MW generator which is permitted under the SQSS. The **Power Park Module** is required to satisfy the requirements of ECC.6.3.16, and an example of the deviation in system voltage at the **Grid Entry Point** and expected reactive current injected by the **Power Park Module** before and during the fault is shown in Figure ECC4.2(a) and (b).

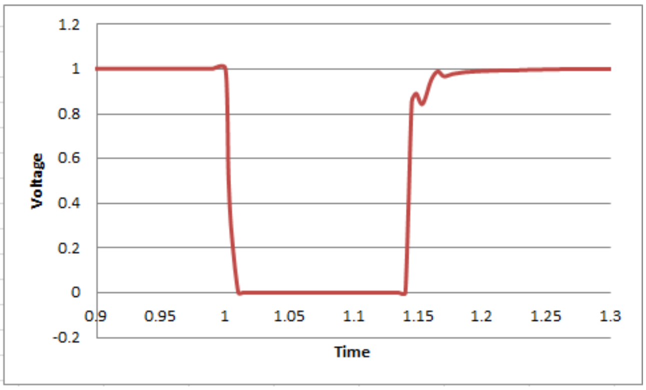


Figure ECC4.2(a) –Voltage deviation at Substation C

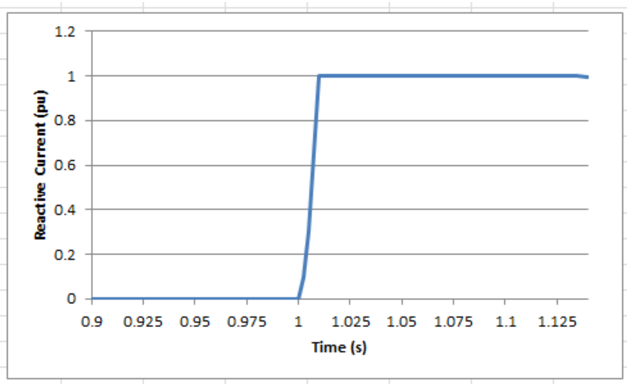


Figure ECC4.2(b) – Reactive Current Injected from the Power Park Module

connected to Substation C

It is important to note that blocking is permitted upon fault clearance in order to limit the impact of transient overvoltages. This effect is shown in Figure ECC4.3(a) and Figure ECC4.3(b)

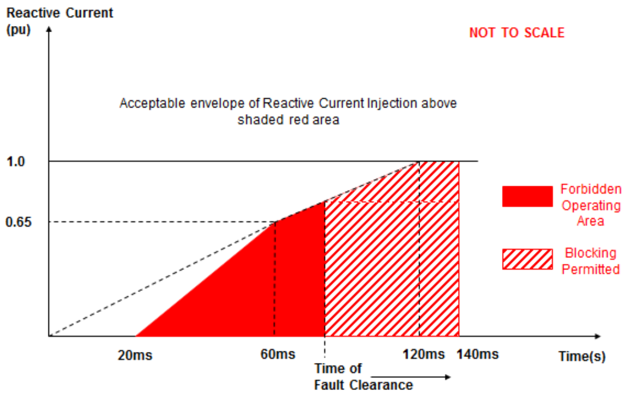


Figure ECC4.3(a)

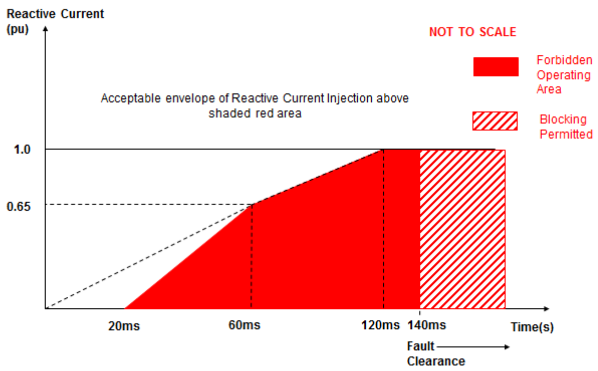


Figure ECC4.3(b)

ECC.4EC1.1.3 So long as the reactive current injected is above the shaded area as illustrated in Figure ECC4.3(a) or ECC4.3(b), the **Power Park Module** would be considered to be compliant with the requirements of ECC.6.3.16 Taking the example outlined in ECC.4EC1.1.1 where the fault is cleared in 140ms, the following diagram in Figure ECC4.4 results.

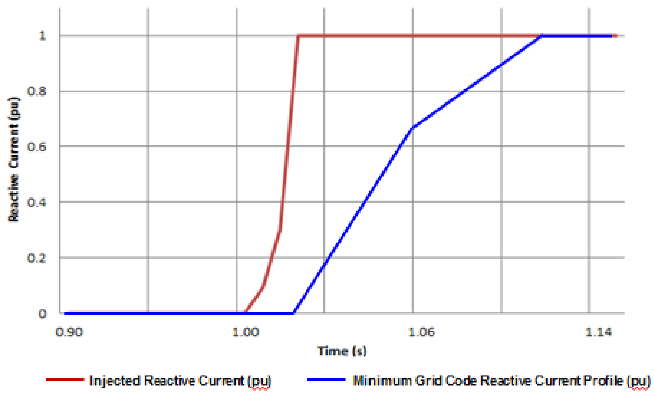


Figure ECC4.4 – Injected Reactive Current from Power Park Module

compared to the minimum required Grid Code profile

ECC.4EC1.2 Fast Fault Current Injection behaviour during a voltage dip at the Connection Point lasting in excess of 140ms

ECC.4EC1.2.1 Under the fault ride through requirements specified in ECC.6.3.15.9 *(Voltage dips cleared in excess of 140ms)*, **Type B**, **Type C** and **Type D Power Park Modules** are also required to remain connected and stable for voltage dips on the **Transmission System** in excess of 140ms. Figure ECC4.4 (a) shows an example of a 500MW **Power Park Module** connected to the **Transmission System** and Figure ECC4.4 (b) shows the corresponding voltage dip seen at the **Grid Entry Point** or **User System Point** which has resulted from a remote fault on the **Transmission System** cleared in a backup operating time of 710ms.

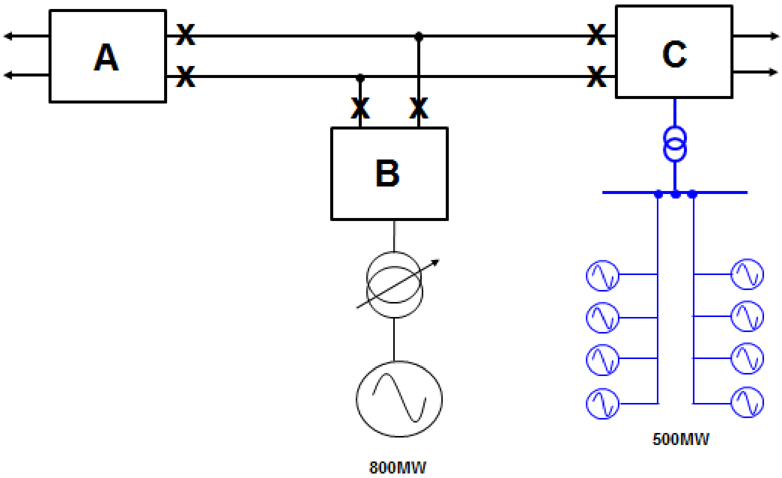


Figure ECC4.4(a)

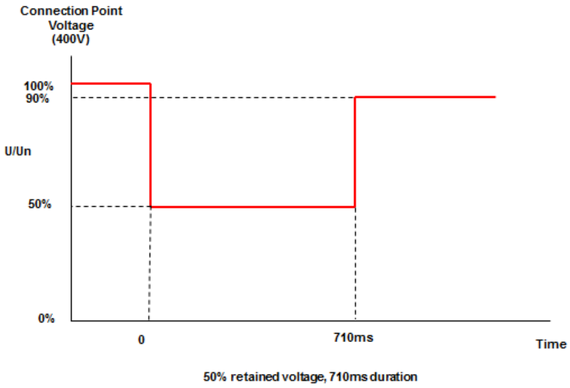


Figure ECC4.4 (b)

ECC.4EC1.2.1 In this example, the voltage dips to 0.5pu for 710ms. Under ECC.6.3.16 each **Type B**, **Type C** and **Type D Power Park Module** is required to inject reactive current into the **System** and shall respond in proportion to the change in **System** voltage at the **Grid Entry Point** or **User System Entry Point** up to a maximum value of 1.0pu of rated current**.** An example of the expected injected reactive current at the **Connection Point** is shown in Figure ECC4.5

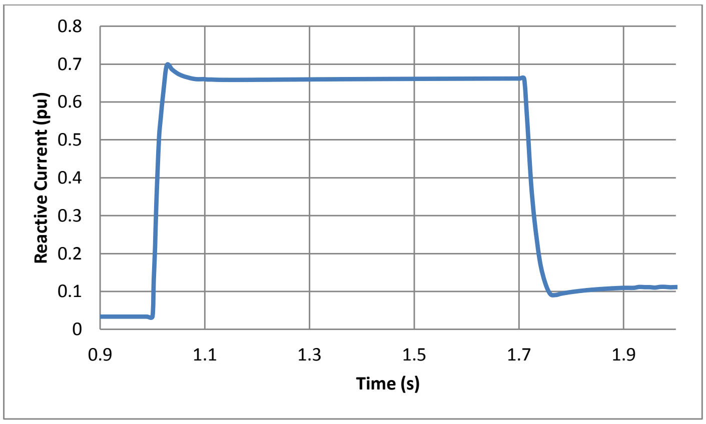


Figure ECC4.5 Reactive Current Injected for a 50% voltage dip for a period of 710ms

APPENDIX E5 - TECHNICAL REQUIREMENTS

LOW FREQUENCY RELAYS FOR THE AUTOMATIC

DISCONNECTION OF SUPPLIES AT LOW FREQUENCY

ECC.A.5.1 Low Frequency Relays

ECC.A.5.1.1 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-parameters specify the requirements of approved **Low Frequency Relays**:

(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**.
(h) Indications	Provide the direction of **Active Power** flow at the point of de-energisation.

ECC.A.5.2 Low Frequency Relay Voltage Supplies

ECC.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 **Power Generating Module** or from another part of the **User System**.

ECC.A.5.3 Scheme Requirements

ECC.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 ECC.A.5.5.1a and is not reduced unacceptably during equipment outage or maintenance conditions.

ECC.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.

ECC.A.5.4 Low Frequency Relay Testing

ECC.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 ECC.A.5.1.1 applicable at the time such **Low Frequency Relays** were commissioned.

ECC.A.5.5 Scheme Settings

ECC.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.

Frequency Hz	% **Demand** disconnection for each Network Operator in Transmission Area		
	NGET	SPT	SHETL
48.8	5		
48.75	5		
48.7	10		
48.6	7.5		10
48.5	7.5	10	
48.4	7.5	10	10
48.2	7.5	10	10

48.0	5	10	10
47.8	5		
Total % **Demand**	60	40	40

Table ECC.A.5.5.1a

Note – the percentages in table ECC.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.

ECC.A.5.6 Connection and Reconnection

ECC.A.5.6.1 As defined under OC.6.6 once automatic low **Frequency Demand Disconnection** has taken place, the **Network Operator** on whose **User System** it has occurred, will not reconnect until **NGET** instructs that **Network Operator** to do so in accordance with OC6. The same requirement equally applies to **Non-Embedded Customers.**

ECC.A.5.6.1 Once **NGET** instructs the **Network Operator** or **Non Embedded Customer** to reconnect to the **National Electricity Transmission System** following operation of the **Low Frequency Demand Disconnection** scheme it shall do so in accordance with the requirements of ECC.6.2.3.10 and OC6.6.

ECC.A.5.6.2 **Network Operator** or **Non Embedded Customers** shall be capable of being remotely disconnected from the **National Electricity Transmission System** when instructed by **NGET**. Any requirement for the automated disconnection equipment for reconfiguration of the **National Electricity Transmission System** in preparation for block loading and the time required for remote disconnection shall be specified by **NGET** in accordance with the terms of the **Bilateral Agreement**.

APPENDIX E6 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR ONSHORE SYNCHRONOUS POWER GENERATING MODULES,

ECC.A.6.1 Scope

ECC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for **Type C** and **Type D Onshore Synchronous Power Generating Modules** that must be complied with by the **User**. This Appendix does not limit any site specific requirements where in **NGET's** reasonable opinion these facilities are necessary for system reasons.

ECC.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 values outside of the ranges provided in this Appendix 6. 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**.

ECC.A.6.1.3 Should an **EU 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 **EU Generator** anticipates making the change. The change may require a revision to the **Bilateral Agreement**.

ECC.A.6.2 Requirements

ECC.A.6.2.1 The **Excitation System** of a **Type C** or **Type D Onshore Synchronous Power Generating Module** shall include an excitation source (**Exciter**), and a continuously acting **Automatic Voltage Regulator** (**AVR**) and shall meet the following functional specification. **Type D Synchronous Power Generating Modules** are also required to be fitted with a **Power System Stabiliser** in accordance with the requirements of ECC.A.6.2.5.

ECC.A.6.2.3 Steady State Voltage Control

ECC.A.6.2.3.1 An accurate steady state control of the **Onshore Synchronous Power Generating Module** pre-set **Synchronous Generating Unit** 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 output of a **Synchronous Generating Unit** within an **Onshore Synchronous Power Generating Module** is gradually changed from zero to rated MVA output at rated voltage, **Active Power** and **Frequency**.

ECC.A.6.2.4 Transient Voltage Control

ECC.A.6.2.4.1 For a step change from 90% to 100% of the nominal **Onshore Synchronous Generating Unit** terminal voltage, with the **Onshore Synchronous Generating Unit** on open circuit, the **Excitation System** response shall have a damped oscillatory characteristic. For this characteristic, the time for the **Onshore Synchronous 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.

ECC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the **Onshore Power Generating Module** 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 Synchronous 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.

ECC.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 Synchronous Generating Unit** terminals. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

ECC.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 ECC.A.6.2.4.3. The specified value will be 80% of the value specified in ECC.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 Synchronous 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 Synchronous 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 if **NGET** identifies a **Transmission System** need.

ECC.A.6.2.5 Power Oscillations Damping Control

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

ECC.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.

ECC.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 the **Synchronous Generating Unit** 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.

ECC.A.6.2.5.4 The output signal from the **Power System Stabiliser** shall be limited to not more than ±10% of the **Onshore Synchronous 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.

ECC.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.

ECC.A.6.2.5.6 The **EU Generator** in respect of its **Type D Synchronous Power Generating Modules** 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 **EU Generator** will provide to **NGET** a report covering the areas specified in ECP.A.3.2.1.

ECC.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 Synchronous Generating Unit**, within a **Type D Synchronous Power Generating Modul**e, the **Power System Stabiliser** may be out of service.

ECC.A.6.2.5.8 Where a **Power System Stabiliser** is fitted to a **Pumped Storage Unit** within a **Type D Synchronous Power Generating Module** it must function when the **Pumped Storage Unit** is in both generating and pumping modes.

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

ECC.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.

ECC.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 ECPA.5.2 and ECPA.5.4. The **Automatic Voltage Regulator** shall include a facility to allow step injections into the **Automatic Voltage Regulator** voltage reference, with the **Onshore Type D Power Generating Module** 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.

ECC.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.

ECC.A.6.2.7 Under-Excitation Limiters

ECC.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 **Synchronous Power Generating Module Excitation System**. The **Under Excitation Limiter** shall prevent the **Automatic Voltage Regulator** reducing the **Synchronous Generating Unit** 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) the **Reactive Power** (MVAr) and to the square of the **Synchronous Generating Unit**r 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 Power Generating Module** at any setting and shall be readily adjustable.

ECC.A.6.2.7.2 The performance of the **Under Excitation Limiter** shall be independent of the rate of change of the **Onshore Synchronous Power Generating Module** load and shall be demonstrated by testing as detailed in ECP.A.5.5. The resulting maximum overshoot in response to a step injection which operates the **Under Excitation Limiter** shall not exceed 4% of the **Onshore Synchronous Generating Unit** rated MVA. The operating point of the **Onshore Synchronous 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 Synchronous Generating Unit** MVA rating within a period of 5 seconds.

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

ECC.A.6.2.8 <u>Over-Excitation and Stator Current Limiters</u>

ECC.A.6.2.8.1 The settings of the **Over-Excitation Limiter** and stator current limiter, shall ensure that the **Onshore Synchronous Generating Unit** excitation is not limited to less than the maximum value that can be achieved whilst ensuring the **Onshore Synchronous Generating Unit** is operating within its design limits. If the **Onshore Synchronous Generating Unit** 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 Synchronous Power Generating Module**.

ECC.A.6.2.8.2 The performance of the **Over-Excitation Limiter**, shall be demonstrated by testing as described in ECP.A.5.6. Any operation beyond the **Over-Excitation Limit** shall be controlled by the **Over-Excitation Limiter** or stator current limiter without the operation of any **Protection** that could trip the **Onshore Synchronous Power Generating Module**.

ECC.A.6.2.8.3 The **EU Generator** shall also make provision to prevent any over-excitation restriction of the **Onshore Synchronous Generating Unit** when the **Excitation System** is under manual control, other than that necessary to ensure the **Onshore Power Generating Module** is operating within its design limits.

APPENDIX E7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR AC CONNECTED ONSHORE POWER PARK MODULES AND OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT HVDC SYSTEMS AND REMOTE END HVDC CONVERTER STATIONS

ECC.A.7.1 Scope

ECC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for **Onshore Power Park Modules**, **Onshore HVDC Converters Remote End HVDC Converter Stations** 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 where in **NGET's** reasonable opinion these facilities are necessary for system reasons. The control performance requirements applicable to **Configuration 2 AC Connected Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules** are defined in Appendix E8.

ECC.A.7.1.2 Proposals by **EU Generators** or **HVDC System Owners** 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** or **HVDC System Owner** anticipates making the change. The change may require a revision to the **Bilateral Agreement**.

ECC.A.7.1.3 In the case of a **Remote End HVDC Converter** at a **HVDC Converter Station,** the control performance requirements shall be specified in the **Bilateral Agreement**. These requirements shall be consistent with those specified in ECC.6.3.2.4. In the case where the **Remote End HVDC Converter** is required to ensure the zero transfer of **Reactive Power** at the **HVDC Interface Point** then the requirements shall be specified in the **Bilateral Agreement** which shall be consistent with those requirements specified in ECC.A.8 . In the case where a wider reactive capability has been specified in ECC.6.3.2.4, then the requirements consistent with those specified in ECC.A.7.2 shall apply with any variations being agreed between the **User** and **NGET**.

ECC.A.7.2 Requirements

ECC.A.7.2.1 **NGET** requires that the continuously acting automatic voltage control system for the **Onshore Power Park Module**, **Onshore HVDC Converter** 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 Power Park Module** or **Onshore HVDC Converter** or **OTSDUW Plant and Apparatus** is connected is restricted such that the full reactive range under the steady state voltage control requirements (ECC.A.7.2.2) cannot be utilised, **NGET** may specify 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.

ECC.A.7.2.2 Steady State Voltage Control

ECC.A.7.2.2.1 The **Onshore Power Park Module**, **Onshore HVDC Converter** 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 ECC.A.7.2.2a.

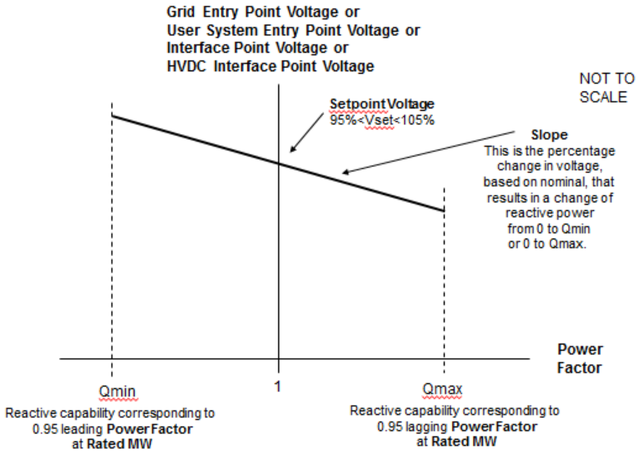


Figure **E**CC.A.7.2.2a

ECC.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 **EU Generator** or **HVDC System Owner** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%. For **Embedded Generators** and **Embedded HVDC System Owners** the **Setpoint Voltage** will be discussed between **NGET** and the relevant **Network Operator** and will be specified to ensure consistency with ECC.6.3.4.

ECC.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 **EU Generator** or **HVDC System Owner** to implement an alternative slope setting within the range of 2% to 7%. For **Embedded Generators** and **Onshore Embedded HVDC Converter Station Owners** the **Slope** setting will be discussed between **NGET** and the relevant **Network Operator** and will be specified to ensure consistency with ECC.6.3.4.

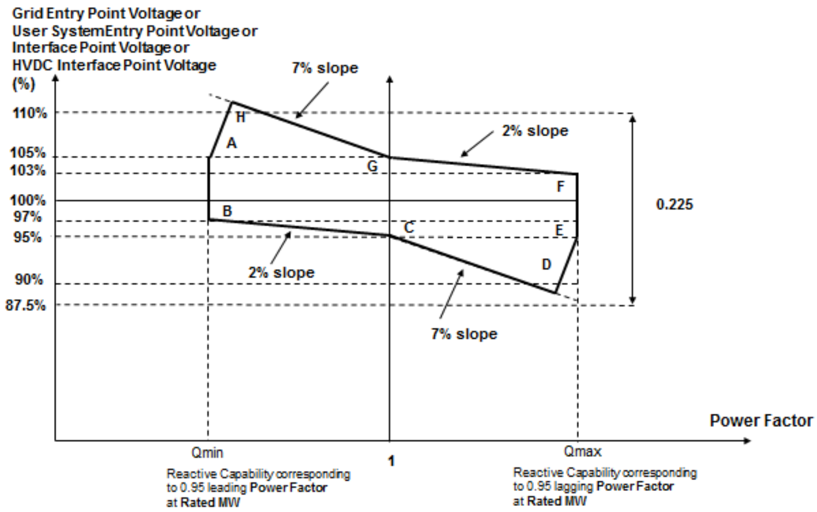


Figure ECC.A.7.2.2b

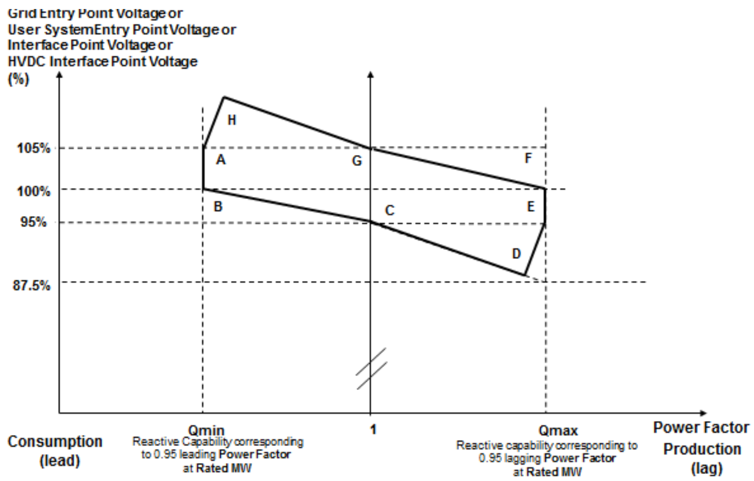


Figure ECC.A.7.2.2c

ECC.A.7.2.2.4 Figure ECC.A.7.2.2b shows the required envelope of operation for **-**, **OTSDUW Plant** and **Apparatus**, **Onshore Power Park Modules** and **Onshore HVDC Converters** except for those **Embedded** at 33kV and below or directly connected to the **National Electricity Transmission System** at 33kV and below. Figure ECC.A.7.2.2c shows the required envelope of operation for **Onshore Power Park Modules Embedded** at 33kV and below, or directly connected to the **National Electricity Transmission System** at

33kV and below. The enclosed area within points ABCDEFGH is the required capability range within which the **Slope** and **Setpoint Voltage** can be changed.

ECC.A.7.2.2.5 Should the operating point of the~~,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, or **Onshore HVDC Converter** deviate so that it is no longer a point on the operating characteristic (figure ECC.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.

ECC.A.7.2.2.6 Should the **Reactive Power** output of the **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** 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 **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **HVDC System** shall maintain maximum lagging **Reactive Power** output for voltage reductions down to 95%. This requirement is indicated by the line EF in figures ECC.A.7.2.2b and ECC.A.7.2.2c as applicable. Should the **Reactive Power** output of the **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, or **Onshore HVDC Converter** 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 **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, or **Onshore HVDC Converter** shall maintain maximum leading **Reactive Power** output for voltage increases up to 105%. This requirement is indicated by the line AB in figures ECC.A.7.2.2b and ECC.A.7.2.2c as applicable.

ECC.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 **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converters** 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 ECC.A.7.2.2b and ECC.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 **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC System Converter** 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 ECC.A.7.2.2b and ECC.A.7.2.2c as applicable. Should the **Reactive Power** output of the **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** reach its maximum lagging limit at an **Onshore Grid Entry Connection 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 Power Park Module**, **Onshore HVDC Converter** shall maintain maximum lagging reactive current output for further voltage decreases. Should the **Reactive Power** output of the **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** reach its maximum leading limit at a **Onshore Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded** or **Interface Point** voltage in the case of an **OTSDUW Plant and Apparatus**) above 105%, the **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.7.2.2.8 All **OTSDUW Plant and Apparatus** must be capable of enabling **EU Code 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.

ECC.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 ECC.A.7.2.1, clause ECC.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**.

ECC.A.7.2.3 Transient Voltage Control

ECC.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~~,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** 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 ECC.A.7.2.3.1a.

(ii) the response shall be such that 90% of the change in the **Reactive Power** output of the~~,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, or **Onshore HVDC Converter** will be achieved within

1. 2 seconds, 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 and

2. 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 ECC.6.3.2 (or, if appropriate ECC.A.7.2.2.6 or ECC.A.7.2.2.7);

(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 5 seconds from achieving 90% of the response as defined in ECC.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 maximum **Reactive Power**.

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

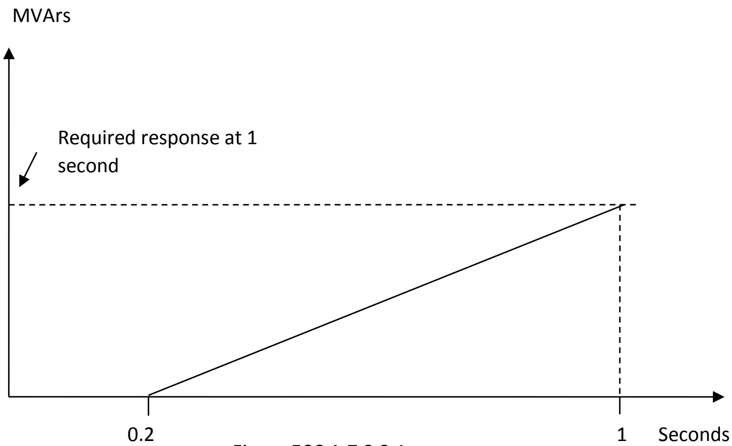


Figure ECC.A.7.2.3.1a

ECC.A.7.2.3.2 **OTSDUW Plant and Apparatus** or **Onshore Power Park Modules** or **Onshore HVDC Converters** 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 ECC.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.

ECC.A.7.2.4 Power Oscillation Damping

ECC.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 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 ECP.A.3.2.2.

ECC.A.7.2.5 Overall Voltage Control System Characteristics

ECC.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**).

ECC.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 **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** or **Onshore HVDC Converter** should also meet this requirement

ECC.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 ECP.A.6.

ECC.A.7.3 **Reactive Power** Control

ECC.A.7.3.1 As defined in ECC.6.3.8.3.4, **Reactive Power** control mode of operation is not required in respect of **Onshore Power Park Modules** or **OTSDUW Plant and Apparatus** or **Onshore HVDC Converters** unless otherwise specified by **NGET** in coordination with the relevant **Network Operator**. However where there is a requirement for **Reactive Power** control mode of operation, the following requirements shall apply.

ECC.A.7.3.2 The **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** or **Onshore HVDC Converter** shall be capable of setting the **Reactive Power** setpoint anywhere in the **Reactive Power** range as specified in ECC.6.3.2.4 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full **Reactive Power**, controlling the reactive power at the **Grid Entry Point** or **User System Entry Point** if **Embedded** to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full **Reactive Power**.

ECC.A.7.3.3 Any additional requirements for **Reactive Power** control mode of operation shall be specified by **NGET** in coordination with the relevant **Network Operator**..

ECC.A.7.4 **Power Factor** Control

ECC.A.7.4.1 As defined in ECC.6.3.8.4.3, **Power Factor** control mode of operation is not required in respect of **Onshore Power Park Modules** or **OTSDUW Plant and Apparatus** or **Onshore HVDC Converters** unless otherwise specified by **NGET** in coordination with the relevant **Network Operator.** However where there is a requirement for **Power Factor** control mode of operation, the following requirements shall apply.

ECC.A.7.4.2 The **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** or **Onshore HVDC Converter** shall be capable of controlling the **Power Factor** at the **Grid Entry Point or User System Entry Point** (if **Embedded**) within the required **Reactive Power** range as specified in ECC.6.3.2.2.1 and ECC.6.3.2.4 to a specified target **Power Factor**. **NGET** shall specify the target **Power Factor** value (which shall be achieved within 0.01 of the set **Power Factor**), its tolerance and the period of time to achieve the target **Power Factor** following a sudden change of **Active Power** output. The tolerance of the target **Power Factor** shall be expressed through the tolerance of its corresponding **Reactive Power**. This **Reactive Power** tolerance shall be expressed by either an absolute value or by a percentage of the maximum **Reactive Power** of the **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** or **Onshore HVDC Converter**. The details of these requirements being pursuant to the terms of the **Bilateral Agreement**.

ECC.A.7.4.3 Any additional requirements for **Power Factor** control mode of operation shall be specified by **NGET** in coordination with the relevant **Network Operator**.

APPENDIX E8 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR CONFIGURATION 2 AC CONNECTED OFFSHORE POWER PARK MODULES AND CONFIGURATION 2 DC CONNECTED POWER PARK MODULES

ECC.A.8.1 Scope

ECC.A.8.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for **Configuration 2 AC Connected Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules** that must be complied with by the **EU Code User**. This Appendix does not limit any site specific requirements that may be specified where in **NGET's** reasonable opinion these facilities are necessary for system reasons.

ECC.A.8.1.2 These requirements also apply to **Configuration 2 DC Connected Power Park Modules**. In the case of a **Configuration 1 DC Connected Power Park Module** the technical performance requirements shall be specified by **NGET**. Where the **EU Generator** in respect of a **DC Connected Power Park Module** has agreed to a wider reactive capability range as defined under ECC.6.3.2.5 and ECC.6.2.3.6 then the requirements that apply will be specified by **NGET** and which shall reflect the performance requirements detailed in ECC.A.8.2 below but with different parameters such as droop and **Setpoint Voltage**.

ECC.A.8.1.3 Proposals by **EU 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**.

ECC.A.8.2 Requirements

ECC.A.8.2.1 **NGET** requires that the continuously acting automatic voltage control system for the **Configuration 2 AC connected Offshore Power Park Module** and **Configuration 2 DC Connected Power Park Module** shall meet the following functional performance specification.

ECC.A.8.2.2 Steady State Voltage Control

ECC.A.8.2.2.1 The **Configuration 2 AC connected Offshore Power Park Module** and **Configuration 2 DC Connected Power Park Module** shall provide continuous steady state control of the voltage at the **Offshore Connection Point** with a **Setpoint Voltage** and **Slope** characteristic as illustrated in Figure ECC.A.8.2.2a.

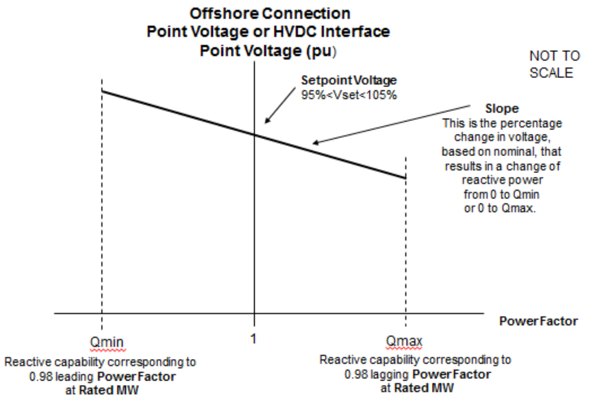


Figure ECC.A.8.2.2a

ECC.A.8.2.2.2 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 **EU Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%.

ECC.A.8.2.2.3 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 **EU Generator** to implement an alternative slope setting within the range of 2% to 7%.

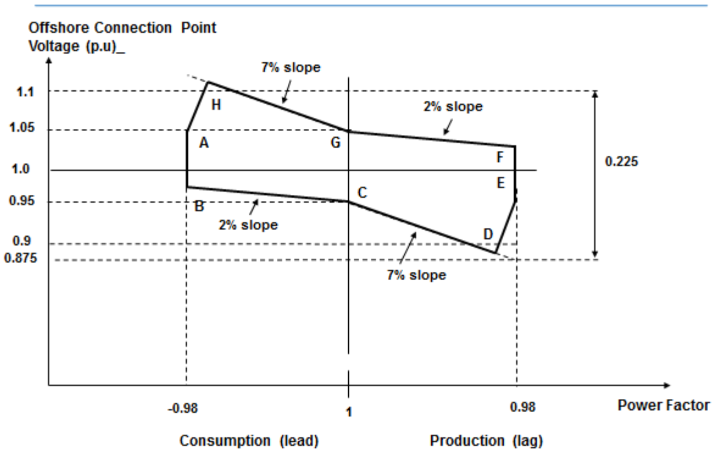


Figure ECC.A.8.2.2b

ECC.A.8.2.2.4 Figure ECC.A.8.2.2b shows the required envelope of operation for **Configuration 2 AC connected Offshore Power Park Module** and **Configuration 2 DC Connected Power Park Module**. The enclosed area within points ABCDEFGH is the required capability range within which the **Slope** and **Setpoint Voltage** can be changed.

ECC.A.8.2.2.5 Should the operating point of the **Configuration 2 AC connected Offshore Power Park or Configuration 2 DC Connected Power Park Module** deviate so that it is no longer a point on the operating characteristic (Figure ECC.A.8.2.2a) 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.

ECC.A.8.2.2.6 Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** reach its maximum lagging limit at an **Offshore Grid Entry Point** or **Offshore User System Entry Point** or **HVDC Interface Point** voltage above 95%, the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected 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 figure ECC.A.8.2.2b. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** reach its maximum leading limit at the **Offshore Grid Entry Point** or **Offshore User System Entry Point** or **HVDC Interface Point** voltage below 105%, the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected 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 ECC.A.8.2.2b.

ECC.A.8.2.2.7 For **Offshore Grid Entry Point** or **User System Entry Point** or **HVDC Interface Point** voltages below 95%, the lagging **Reactive Power** capability of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected 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 ECC.A.8.2.2b. For **Offshore Grid Entry Point** or **Offshore User System Entry Point** voltages or **HVDC Interface Point** voltages above 105%, the leading **Reactive Power** capability of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected 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 ECC.A.8.2.2b. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** reach its maximum lagging limit at an **Offshore Grid Entry Point** or **Offshore User System Entry** voltage or **HVDC Interface Point** voltage below 95%, the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** shall maintain maximum lagging reactive current output for further voltage decreases. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** reach its maximum leading limit at an **Offshore Grid Entry Point** or **Offshore User System Entry** voltage or **HVDC Interface Point** voltage above 105%, the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.8.2.3 Transient Voltage Control

ECC.A.8.2.3.1 For an on-load step change in **Offshore Grid Entry Point** or **Offshore User System Entry Point** voltage or **HVDC 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 **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected 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 ECC.A.8.2.3.1a.

(ii) the response shall be such that 90% of the change in the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** will be achieved within

3.2 seconds, 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 and

4.1 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 ECC.6.3.2 (or, if appropriate ECC.A.8.2.2.6 or ECC.A.8.2.2.7);

(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 5 seconds from achieving 90% of the response as defined in ECC.A.8.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum **Reactive Power**.

(v) following the transient response, the conditions of ECC.A.8.2.2 apply.

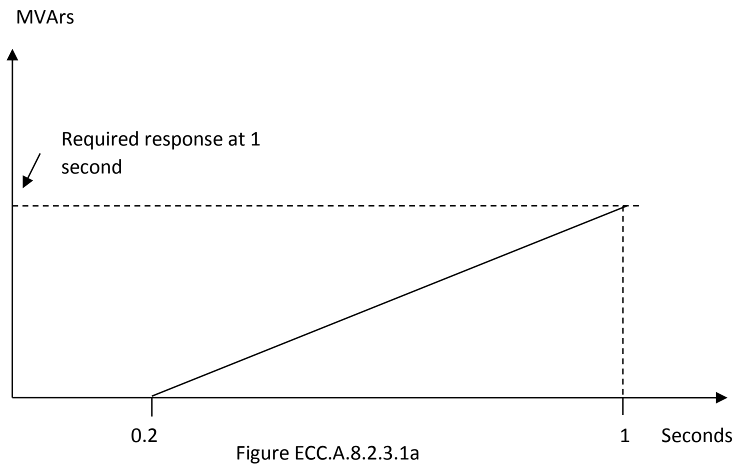


Figure ECC.A.8.2.3.1a

ECC.A.8.2.3.2 **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** shall be capable of

(a) changing their **Reactive Power** output from maximum lagging value to 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 **Reactive Power** output from zero to 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 ECC.A.8.2.3.1 where the change in **Reactive Power** output is in response to an on-load step change in **Offshore Grid Entry Point** or **Offshore User System Entry Point** voltage or **HVDC Interface Point** voltage.

ECC.A.8.2.4 Power Oscillation Damping

ECC.A.8.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a **Power System Stabiliser (PSS)** shall be specified 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** or **HVDC System Owner** will provide to **NGET** a report covering the areas specified in ECP.A.3.2.2.

ECC.A.8.2.5 Overall Voltage Control System Characteristics

ECC.A.8.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in **Offshore Grid Entry Point** or **Offshore User System Entry Point** or **HVDC Interface Point** voltage.

ECC.A.8.2.5.2 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 **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** should also meet this requirement

ECC.A.8.2.5.3 The response of the voltage control system (including the **Power System Stabiliser** if employed) shall be demonstrated by testing in accordance with ECP.A.6.

ECC.A.8.3 **Reactive Power** Control

ECC.A.8.3.1 **Reactive Power** control mode of operation is not required in respect of **Configuration 2 AC connected Offshore Power Park Modules** or **Configuration 2 DC Connected Power Park Modules** unless otherwise specified by **NGET**. However where there is a requirement for **Reactive Power** control mode of operation, the following requirements shall apply.

ECC.A.8.3.2 **Configuration 2 AC connected Offshore Power Park Modules** or **Configuration 2 DC Connected Power Park Modules** shall be capable of setting the **Reactive Power** setpoint anywhere in the **Reactive Power** range as specified in ECC.6.3.2.8.2 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full **Reactive Power**, controlling the **Reactive Power** at the **Offshore Grid Entry Point or Offshore User System Entry Point** or **HVDC Interface Point** to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full **Reactive Power**.

ECC.A.8.3.3 Any additional requirements for **Reactive Power** control mode of operation shall be specified by **NGET**.

ECC.A.8.4 **Power Factor** Control

ECC.A.8.4.1 **Power Factor** control mode of operation is not required in respect of **Configuration 2 AC connected Offshore Power Park Modules** or **Configuration 2 DC Connected Power Park Modules** unless otherwise specified by **NGET**. However where there is a requirement for **Power Factor** control mode of operation, the following requirements shall apply.

ECC.A.8.4.2 **Configuration 2 AC connected Offshore Power Park Modules** or **Configuration 2 DC Connected Power Park Modules** shall be capable of controlling the **Power Factor** at the **Offshore Grid Entry Point** or **Offshore User System Entry Point** or **HVDC Interface Point** within the required **Reactive Power** range as specified in ECC.6.3.2.8.2 with a target **Power Factor**. **NGET** shall specify the target **Power Factor** (which shall be achieved to within 0.01 of the set **Power Factor**), its tolerance and the period of time to achieve the target **Power Factor** following a sudden change of **Active Power** output. The tolerance of the target **Power Factor** shall be expressed through the tolerance of its corresponding **Reactive Power**. This **Reactive Power** tolerance shall be expressed by either an absolute value or by a percentage of the maximum **Reactive Power** of the **Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module.** The details of these requirements being specified by **NGET**.

ECC.A.8.4.3 Any additional requirements for **Power Factor** control mode of operation shall be specified by **NGET**.

< END OF EUROPEAN CONNECTION CONDITIONS >

Making a positive difference
for energy consumers

Electricity Distribution Licensees,
Distribution Code Review Panel
(DCRP), Grid Code Review Panel
Chair, GCRP, and other
interested parties

Email: peter.bingham@ofgem.gov.uk

Date: 22 June 2018

Dear Electricity Distribution Licensees and GCRP chair,

Our decision to send back modification proposal DCRP/MP/18/01 'Revision to Engineering Recommendation P28 (Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom)' (DCRP/MP/18/01)

On 17 May 2018, the electricity distribution licensees submitted a Final Modification Report (FMR) for Distribution Code modification proposal DCRP/MP/18/01 to us. We have decided that we cannot form an opinion on this modification proposal based on the FMR as submitted. We are therefore sending the FMR back to industry for further work.

We consider that there has not been sufficient industry consideration of the impact of DCRP/MP/18/01 on other industry codes. Specifically, we do not consider that the impact on the Grid Code has been properly considered. We note that Engineering Recommendation P28[1] is referenced multiple times within the Grid Code. The changes proposed under DCRP/MP/18/01, which have a direct impact on the requirements for parties connecting to the electricity networks, could result in consequential changes to Grid Code requirements that have not been assessed and which may be relevant to inform our decision.

We expect distribution licensees and the Grid Code Review Panel ('GCRP') to work together and submit any proposed Distribution and Grid Code changes to us as a package, which should include co-ordinated implementation timetables. We expect the GCRP to discuss the issues set out in this letter and DCRP/MP/18/01 at the next GCRP meeting, on 28 June 2018.

We therefore direct that the FMR be sent back to the electricity distribution licensees to be reviewed once work to assess the impact of DCRP/MP/18/01 on the Grid Code is complete. To achieve this, we expect the relevant Code Administrators (CA) to follow Principle 13[2] of the CA Code of Practice. [3]

This should be carried out as soon as practicable.

[1] Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom, please see http://www.dcode.org.uk/assets/uploads/ENA_ER_P28_Issue_1__1989_.pdf
[2] CA will ensure cross code coordination to progress changes efficiently where modifications impact multiple codes.
[3] https://www.ofgem.gov.uk/publications-and-updates/code-administration-code-practice-version-4

Yours faithfully,

Peter Bingham
Chief Engineer
Signed on behalf of the Authority and authorised for that purpose

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Modification	At what stage is this document in the process?
# DCRP/MP/18/01/Report to Authority **Revision to Engineering Recommendation P28 "*Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom*"**	01 Modification 02 DCRP report 03 Public Consultation 04 Final Modification Report

The purpose of this report is to assist the Authority in its decision to implement the proposed modifications to the Distribution Code and Engineering Recommendation P28 (subsequently referred to as EREC P28). The proposed modifications were subject to industry consultation in January 2018. Responses from this consultation show that the industry is in favour of these modifications.

Date of publication: 17th May 2018

Recommendation

The Distribution Code Review Panel (DCRP) and the distribution network licencees recommend that modifications are made to the Distribution Code and Engineering Recommendation P28, in relation to voltage fluctuations resulting from the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom that address the following:

a) Introduce requirements and planning levels for Rapid Voltage Changes (RVCs).

b) Improve definition and clarity of 'worst case operating conditions' to be used in the assessment of voltage fluctuations.

c) Include an intermediate planning level and associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV to improve co-ordination of flicker severity from higher to lower voltage supply systems.

d) Improve the definition of voltage step change.

e) Clarify information requirements for assessment and responsibilities for provision of information.

f) Include the application of transfer coefficients for determining voltage fluctuation contributions from different nodes.

g) Assess voltage fluctuations caused by renewable energy and low carbon technologies.

	The Proposer recommends that this modification should be: Submitted to the Authority for approval
	High Impact: None
	Medium Impact: New developers of embedded generation installations, new demand users and existing users that make changes to existing installations with significant number of transformers that cause rapid voltage changes (RVCs) when energised, who are required to design their installations in accordance with the requirements and planning levels for RVCs in EREC P28.
	Low Impact: All Users of the Distribution System. The modifications are intended not to unduly impact on or cause interference to existing Users of public electricity systems/networks. Users that propose to connect disturbing equipment/fluctuating installations to the system, which could result in flicker, who need to carry out assessments and measurements in accordance with EREC P28.

Contents

Any questions?

Contact:
David Spillett

dcode@energynetworks.org

020 7706 5124

Proposer: **DCRP**

www.dcode@energynetworks.org

020 7706 5124

Document Control

Version	Date	Author	Change Reference
0.1	02/03/2018	ENA	Draft Report
0.2	12/03/2018	ENA	Minor Changes
0.3	19/03/2018	ENA	Timetable and implementation section modified
0.4	09/04/2018	ENA	Modified to address comments from 5/4/18 DCRP Panel meeting

Timetable

Work Group Report presented to Panel	24/11/2017
Draft Modification Report issued for consultation	08/01/2018
Consultation Closed	31/01/2018
Final Modification Report available for Panel	20/03/2018
Final Modification Report submitted to Authority	16/05/2018

1. Executive Summary

1.1 EREC P28 was first published in 1989 to provide recommended planning limits for voltage fluctuations for connection of equipment to public electricity supply systems in the UK. Issue 1 was primarily concerned with assessment of voltage fluctuations and associated flicker produced by traditional domestic, commercial and industrial loads.

1.2 Since EREC P28 was first published, the factors affecting development of transmission systems and distribution networks, and equipment connected to them have changed significantly. There has been a shift towards connection of distributed/embedded generation equipment powered by renewable energies and other low carbon technology equipment. These types of modern equipment are capable of causing voltage fluctuations.

1.3 Significant developments in Electromagnetic Compatibility (EMC) requirements have also taken place, which are captured in the International Electrotechnical Commission (IEC) 61000 series of Standards and technical reports. United Kingdom implementation of these Standards is captured in the various parts of BS EN 61000.

1.4 In addition to being a Distribution Code Annex 1 qualifying standard, EREC P28 is referenced in the Grid Code hence a joint Distribution Code and Grid Code Working Group was established to oversee the revision of EREC P28 and associated modification to requirements for voltage fluctuation in the Distribution Code. The Terms of Reference for the Working Group can be found in Annex 9.1 to this report. This Report to Authority (RTA) relates to the proposed changes to the Distribution Code and associated Qualifying Standards. Any necessary changes to the Grid Code will be governed separately by the Grid Code Review Panel.

1.5 Consequently, proposed modifications to EREC P28 (subsequently referred to as EREC P28 Issue 2) and associated modifications to the Distribution Code were developed by the Working Group. Section 4 [of this report] details the Working Group's discussions and details concerning material modifications to EREC P28.

1.6 The scope of EREC P28 has been modified to cover voltage fluctuations that are characterised as RVCs as well as those that result in flicker. The requirements in EREC P28 Issue 2 apply to new connections of customer disturbing equipment to the public electricity supply system as well as changes to existing connections, in so far as they affect voltage fluctuation. EREC P28 Issue 2 is not intended to be applied retrospectively to existing connections that have been previously assessed under Issue 1 of EREC P28 and which remain unchanged.

1.7 The proposed EREC P28 Issue 2 (see Annex 9.7) constitutes a full technical revision of Issue 1. The main technical modifications in EREC P28 Issue 2 include the following.

- Introduction of requirements and planning levels for RVCs.
- Improved definition and clarity of worst case operating conditions to be used in the assessment of voltage fluctuations.
- An intermediate planning level and associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV.

- Improved definition of voltage step change.
- Improved clarity concerning information requirements for assessment and responsibilities for provision of information.
- Concept of transfer coefficients for determining voltage fluctuation contributions from different nodes.
- Additional recommendations for assessing voltage fluctuations caused by renewable energy and low carbon technologies.

1.8 Distribution Code public consultation (DCRP/PC/18/01) was published on the 8th January 2018 and sought views from industry stakeholders on the proposed modification to Engineering Recommendation P28. The Consultation Pack can be found in Annex 9.2 to this report. The deadline for responses was the 31st January 2018.

1.9 A number of responses to the Distribution Code public consultation were received. All of the respondents agreed that the modification proposal:

- better facilitates the Distribution Code objectives;
- provides improved clarity of what constitutes ‘worst case normal operating conditions’;
- assists with co-ordination of the transfer of flicker severity from higher voltage to lower voltage supply systems through the intermediate planning level proposed.

Two respondents provided extensive comments in relation to the proposed requirements and planning levels for RVCs as provided in Figure 5, Figure 6, Figure 7 and Table 4 of EREC P28 Issue 2. The Working Group’s full response can be found in Annex 9.3 to this report. A summary of the consultation responses can be found in Section 5 of this Report to Authority.

1.10 No major impacts have been identified by the Working Group.

1.11 The most significant medium impact of the modification affects those Users, who are required to assess and measure RVCs for conformance against EREC P28 Issue 2 requirements. In particular, developers of embedded generation installations with significant numbers of transformers that cause RVCs when energised, who are required to design their installations in accordance with the requirements and planning levels for RVCs in EREC P28 Issue 2. This modification allows for a greater number of RVCs at any point in the system in a given calendar year to facilitate disconnection and reconnection of complete customer sites with significant numbers of transformers for infrequent or very infrequent switching operations, including unplanned outages, with the ability to re-establish distributed generation more quickly after an unplanned outage, e.g. fault outage.

1.12 The assessment of the Working Group is that the proposed amendments will better facilitate the Distribution Code objectives. A more detailed commentary on the impacts and assessment of the proposed modification can be found in Section 6 of this report.

1.13 The Working Group has made a number of recommendations in Section 7 of this report, the principal one being that EREC P28 Issue 2 as it was consulted upon

(Annex 9.2 - ENA_EREC_P28_Issue 2_2017_Final Draft_v3.5_Issued') is approved and implemented subject to the proposed amendments.

1.14 At the meeting of the Distribution Code Review Panel (the Panel) held on 05/04/2018, a number of clarifications on the Report to Authority were requested. Subsequently, the Panel were consulted via email on a small number of amendments. The Panel were content with the amendments and therefore agreed to the submission of this amended Report to Authority and the Final amended version of P28 Issue 2 (Annex 9.7 - ENA_EREC_P28_Issue 2_2017_Final Draft_v3.7_Issued') as the Panel agreed that the Modification proposal better facilitated the objectives of the Distribution Code.

2. Purpose & Scope of the Working Group

2.1 Purpose

2.1.1 The joint Working Group of various key stakeholders was constituted by the Grid Code Review Panel (GCRP) and the Distribution Code Review Panel (DCRP) of Great Britain (GB) to review Engineering Recommendation P28 Issue 1 1989. Facilitation of the Working Group was provided by the Energy Networks Association (ENA). The first meeting of the working group took place on the 9 December 2014.

2.1.2 The purpose of the Working Group was as follows.

- To review the standards and processes employed by Distribution Network Operators (DNOs) and Transmission System Operators (TSOs) in GB for assessing voltage fluctuations and associated light flicker produced by potentially disturbing User equipment.
- To revise Engineering Recommendation P28 in light of the recommendations from the Working Group.

2.2 Scope

The scope of the Working Group included the following aspects.

2.2.1 General

a) Update references and associated recommendations in EREC P28, including standards.

b) Consider whether it is appropriate to employ different standards and/or processes for transmission compared with distribution connections.

c) Consider issues where EREC P28 is unclear and provide guidance on interpretation (e.g. which fault level to consider).

d) Consider voltage fluctuations from a wider network context and the adequacy of voltage fluctuation requirements in DPC4 of the Distribution Code.

2.2.2 Standards

a) Consider whether there are standards that could be adopted/referenced (e.g. PD IEC/TR 61000-3-7) in anticipation of the implementation of EU Network Codes.

Consideration will be given to reviewing IEEE Standards, where there is no appropriate National, European or International Standard.

b) Consider whether BS EN 61000-3-3 and BS EN 61000-3-11 are effective at controlling flicker for multiple LV installations.

c) Consider whether other technical standards or recommendations would need to change as a result of any change to EREC P28.

2.2.3 Limits

a) Consider whether the planning limits for voltage fluctuations and flicker are adequate or acceptable, in particular for infrequent switching events and rapid voltage changes.

b) Consider whether changes are necessary because of the new range of lighting technologies.

c) Consider whether transformer magnetising inrush should be within the scope of EREC P28.

d) Consider requirements for guidance on the application of EREC P28 and data requirements for use in models/calculations of flicker severity, in particular, data accuracy and any initial conditions to be used.

2.2.4 Evaluation of background levels

a) Clarify the interpretation of measured background values and what duration of measurement is appropriate.

b) Consider how to progress with flicker measurements where a new substation is not yet built (i.e. how is the background level at a new substation best estimated?)

2.2.5 'First-come, first-served' versus allocation of rights

a) Consider the process used to allocate the limits described in EREC P28 between different Users in similar areas including whether 'first-come, first-served' is the appropriate way of allocating limits or whether there are alternative methods (e.g. equal rights as per PD IEC/TR 61000-3-7) that can be justified.

b) Consider how 'competing' applications are dealt with and how changes to customers' requirements may impact on their right to produce voltage fluctuations and flicker.

c) Research whether other countries have moved from 'first-come, first served' to 'equal rights' and consider whether any lessons can be learned.

2.2.6 Other technical issues

a) Develop proposals to update EREC P28 to fully cover the variety of equipment now commonly encountered.

b) Consider the best approach to co-ordinate ‘outages’ between transmission and distribution systems under fault level consideration (e.g. one transmission Supergrid transformer out at the same time as one distribution 132 kV feeder).

3. Why change?

3.1 General

3.1.1 Engineering Recommendation (ER) P28, P*lanning Limits for Voltage Fluctuations Caused by Industrial, Commercial and Domestic Equipment in the United Kingdom* was first published in 1989. Although EREC P28 has proven to be a valuable technical document that has served industry stakeholders well, many important changes affecting its scope and recommendations have taken place in the intervening period. In particular, the following aspects were identified as needing to be addressed in the revision of EREC P28.

3.1.2 Changes to standards, limits and allocation of rights

a) Standards used in Stage 1 assessments (i.e. BS 5406) are now withdrawn.

b) The EMC Directive and subsequent EMC Regulations have introduced new standards that now apply to LV equipment (i.e. BS EN 61000-3-3 and BS EN 61000-3-11).

c) BS EN 61400-21 used in disturbance assessment of large wind turbines is not referenced.

d) Stage 3 of EREC P28 involves taking background measurements of flicker but no guidance is provided on whether to use maximum values or those based on a level not exceeded for a specified percentage of time. Engineering Recommendation G5/4-1 concerning harmonics accounts for this using the 95% of time concept and a similar approach may be justified for flicker.

e) PD IEC/TR 61000-3-7 has been published and introduces new concepts worthy of consideration; namely:

i) Margins between ‘Planning Levels’ and ‘Compatibility Levels’ to allow co-ordination of flicker between voltage levels.

ii) Planning limits for rapid voltage changes occurring less frequently than once every 10 minutes with the limits varying with how often the changes occur. This includes indicative limits with the highest reaching 6% for rapid voltage changes occurring up to two times a day at medium voltage.

iii) Apportionment according to agreed supply capacity. NOTE: EREC P28 Issue 1 allows a first-comer to utilise the whole margin; consideration was given, in cases of multiple connection applications, to some form of apportionment according to agreed supply capacity. A similar issue is being considered for harmonics in the G5/4-1 joint Panel working group.

3.1.3 Changes in networks and codes

a) Discussions are in progress with European Transmission Network Operators (ENTSO-E) concerning harmonised EU Network Codes. Documents such as PD IEC/TR 61000-3-7 may be referenced and so the impact on EREC P28 needed to be considered.

b) The Distribution Code now includes limitation on voltage fluctuations due to transformer magnetising inrush current. A review considered whether inrush should be included within the scope of EREC P28 and what the appropriate limit would be.

NOTE 1: This was also linked to consideration of the PD IEC/TR 61000-3-7 rapid voltage change indicative planning limits and associated CIGRE work. NOTE 2: A separate paper - PP11/51 - related to this was presented to the GCRP by National Grid on 22/09/2011.

c) EREC P28 Issue 1provides somewhat contradictory statements with regards to which fault level – normal or abnormal – should be used in Stage 2 and 3 assessments.

3.1.4 Changes in connections and lighting technology

a) Lighting technology is changing and modern lights have a different flicker performance than the 60 W tungsten filament lamp upon which the flicker limits in EREC P28 Issue 1 are based. Work in this area is underway at IEC level.

b) LV equipment subject to restricted connection falling within the scope of BS EN 61000-3-11 is supposed to be connected only after the customer checks that the network has sufficiently low impedance. The manufacturer is supposed to make a statement to this effect where it applies. However, in reality the manufacturer statement is often not provided or only on request and customers/installers fail to make the relevant checks. Furthermore, the impacts need to be understood of the widespread adoption of heat pumps and electric boilers, which can operate at similar times in large numbers, and the fact that BS EN 61000-3-11 allows higher levels of flicker than the EREC P28 Stage 2 limit.

c) LV equipment subject to BS EN 61000-3-3 is intended for unconditional connection. However, this standard allows higher flicker levels than the EREC P28 Issue 1 Stage 2 limit at the supply terminals and it may be possible to exceed compatibility levels with multiple installations (i.e. when a whole housing estate has such equipment operating at similar times).

4. Work Group Discussions

4.1 General

4.1.1 The Work Group agreed that EREC P28 Issue 1 should be a full technical revision and that the document should be completely restructured and formatted in line with recent ENA engineering documents.

4.1.2 It was agreed that EREC P28 would be revised so that EREC P28 Issue 2 can continue to be read as a ‘standalone’ document.

4.1.3 Appendix D of EREC P28 Issue 1, containing network impedance characteristics, was agreed to be obsolete and has been removed from the revision.

4.2 Changes to standards, limits and allocation of rights

Standards

4.2.1 The Work Group agreed that opportunity should be taken to align, wherever possible, terms and requirements in EREC P28 Issue 2 with those in the IEC 61000 series of Standards (or equivalent BS EN Standards, where they are published), where appropriate. Consequently, the Stage 1 flicker assessment in EREC P28 Issue 2 now aligns with the test requirements in BS EN 61000-3-3 and BS EN 61000-3-11, as applicable to the nature of the equipment and connection. In addition, methods for measuring and assessing voltage fluctuations from wind turbines now align with BS EN 61400-21. EREC P28 Issue 2 adopts requirements in BS EN 61000-4-15 in relation to flickermeters and BS EN 60868 for evaluation of flicker severity. Although consideration was given to IEEE Standards, the trend has been for these Standards to adopt requirements of IEC Standards in the area of voltage fluctuation, and hence reference to IEEE Standards was considered to be of limited value.

4.2.2 The Work Group reviewed how effective BS EN 61000-3-3 and BS EN 61000-3-11 are at controlling flicker for multiple LV installations. The review did not identify issues relating to planning limits being exceeded, where multiple equipment installations are installed on the same LV network, providing that individual equipment being connected complies with limits in BS EN 61000-3-3 or BS EN 61000-3-11, as appropriate, and that similar equipment is under independent control. EREC P28 Issue 2 now includes the requirement to consider the control of multiple equipment to prevent excessive voltage fluctuations.

4.2.3 The Working Group did not identify any global technical standards or engineering recommendations that would need to change as a result of any change to EREC P28 except for changes to relevant text in the Distribution Code, Grid Code and Engineering Recommendation G59 (see Section 6).

4.2.4 In light of the method in PD IEC TR 61000-3-7, planning levels and measurements of P_{st} and P_{lt} stated in EREC P28 Issue 2 are based on 95% probability values.

Limits

4.2.5 The planning levels for flicker severity at any point of the supply system are currently stated in Table 1 of Engineering Recommendation P28 Issue 1.

Table 1 of Engineering Recommendation P28 Issue 1

Supply system Nominal voltage	Planning level	
	P_{st}	P_{lt}
132 kV and below	1.0	0.8
Above 132 kV	0.8	0.6

4.2.6 The short-term flicker severity planning level (P_{st}) is currently 1.0 for supply systems with a nominal voltage of 132 kV and below. Given that the current planning level for these supply systems is the same as the low voltage (LV) compatibility level, the Working Group concluded there was opportunity to adjust the existing planning levels to improve the co-ordination of flicker transfer from higher voltage to lower voltage supply systems.

4.2.7 Table 2 of EREC P28 Issue 2 captures the Working Group's proposal for an intermediate planning level and associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV.

Table 2 of Engineering Recommendation P28 Issue 2

Supply system Nominal voltage	Planning level	
	P_{st}	P_{lt}
LV	1.0	0.8
3.3 kV, 6.6 kV, 11 kV, 20 kV, 33 kV	0.9	0.7
66 kV, 110 kV, 132 kV, 150 kV, 200 kV, 220 kV, 275 kV, 400 kV	0.8	0.6

4.2.8 This proposal is intended to improve the co-ordination of flicker transfer from higher voltage to lower voltage supply systems, which will reduce the possibility of background flicker severity levels exceeding compatibility limits at LV from the transfer of voltage fluctuations down through the supply system.

Rapid Voltage Changes (RVCs)

4.2.9 A key consideration for the Working Group was the introduction of new recommendations for assessment and limits for RVCs as distinct from separate flicker assessment and limits. Early meetings of the Working Group identified the need to address the omission of recommendations and limits for RVCs in Engineering Recommendation P28 Issue 1, particularly given the increased embedded generation connected to systems and the associated need to energise significant numbers of transformers, e.g. wind turbine transformers, with RVC characteristics from time to time.

4.2.10 The voltage envelopes for RVC events proposed by the Working Group in the figures below are replicated from EREC P28 Issue 2 (see Figure 5, Figure 6 and Figure 7). These limits take into account those in the recent GC0076 modification to the Grid Code.

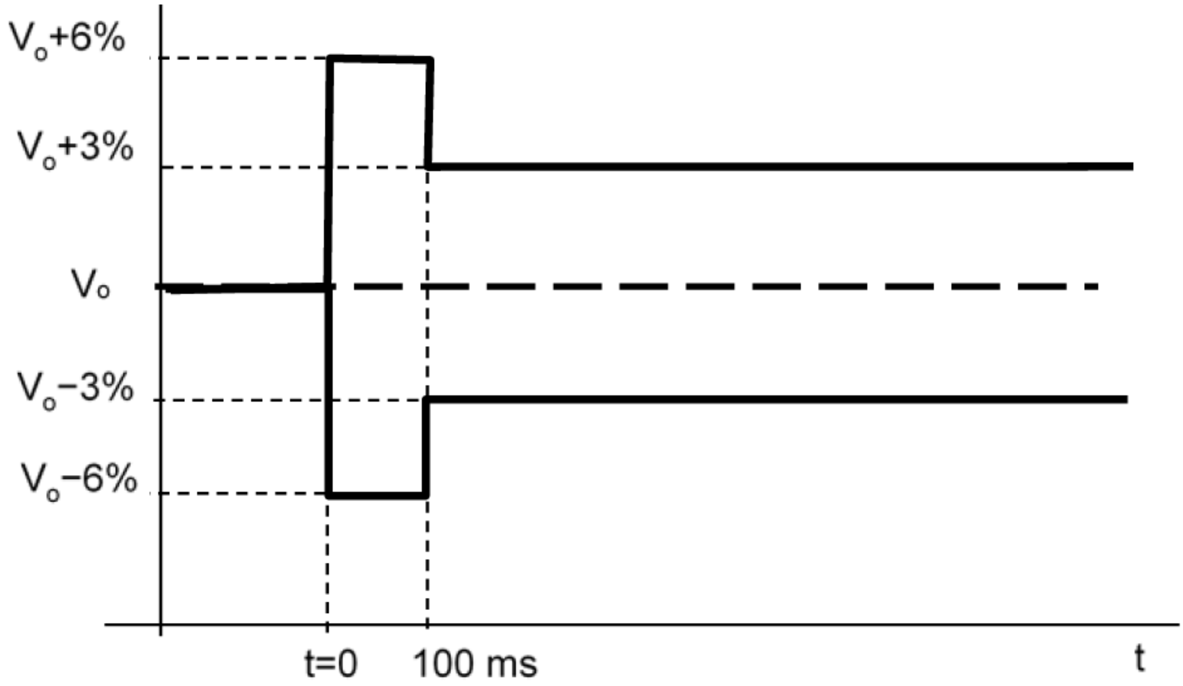


Figure 5 — Voltage characteristic for frequent events (Category 1)

4.2.11 The minimum interval between frequent events fitting within the envelope in Figure 5 is determined by conformance to flicker severity (P_{st}) limits in EREC P28 Issue 2.

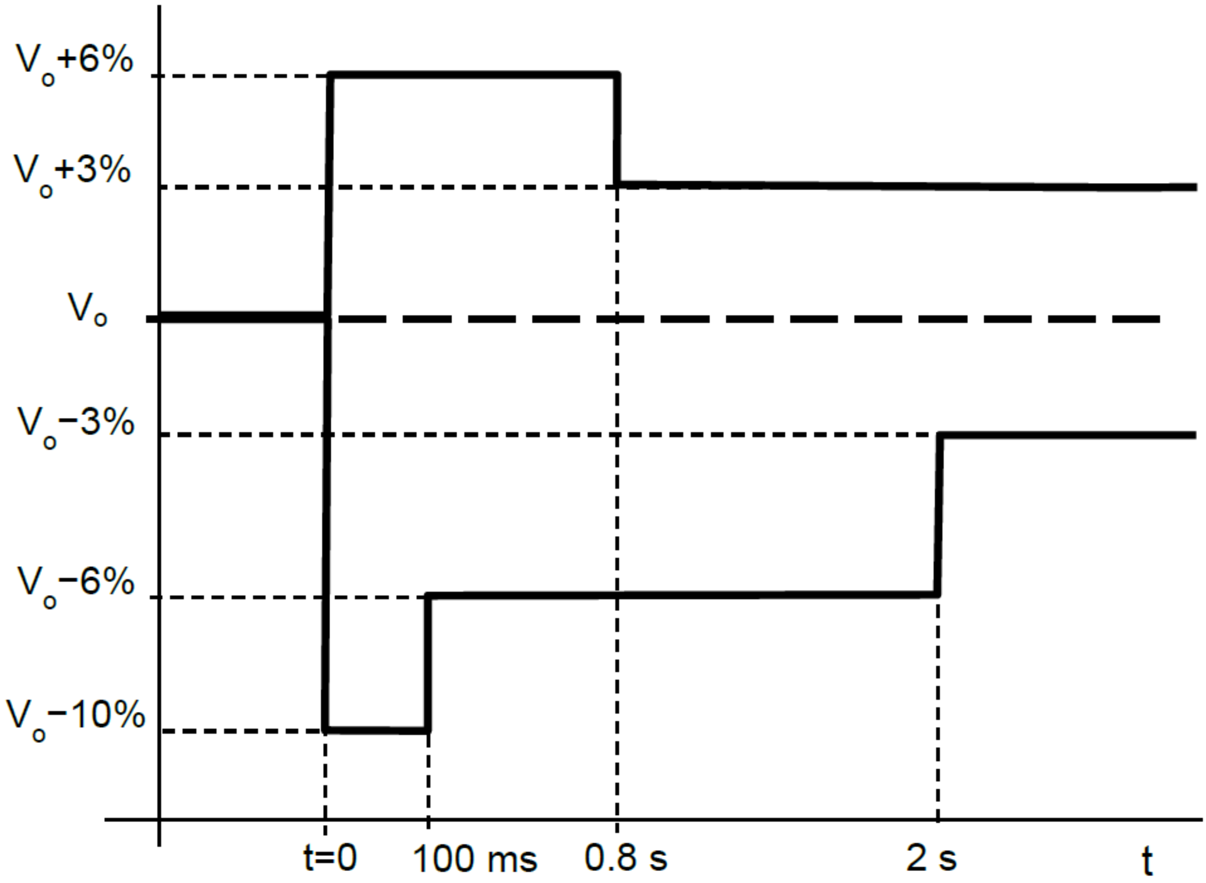


Figure 6 — Voltage characteristic for infrequent events (Category 2)

4.2.12 Up to 4 RVC events per calendar month are permitted for voltage fluctuations fitting within the envelope in Figure 6.

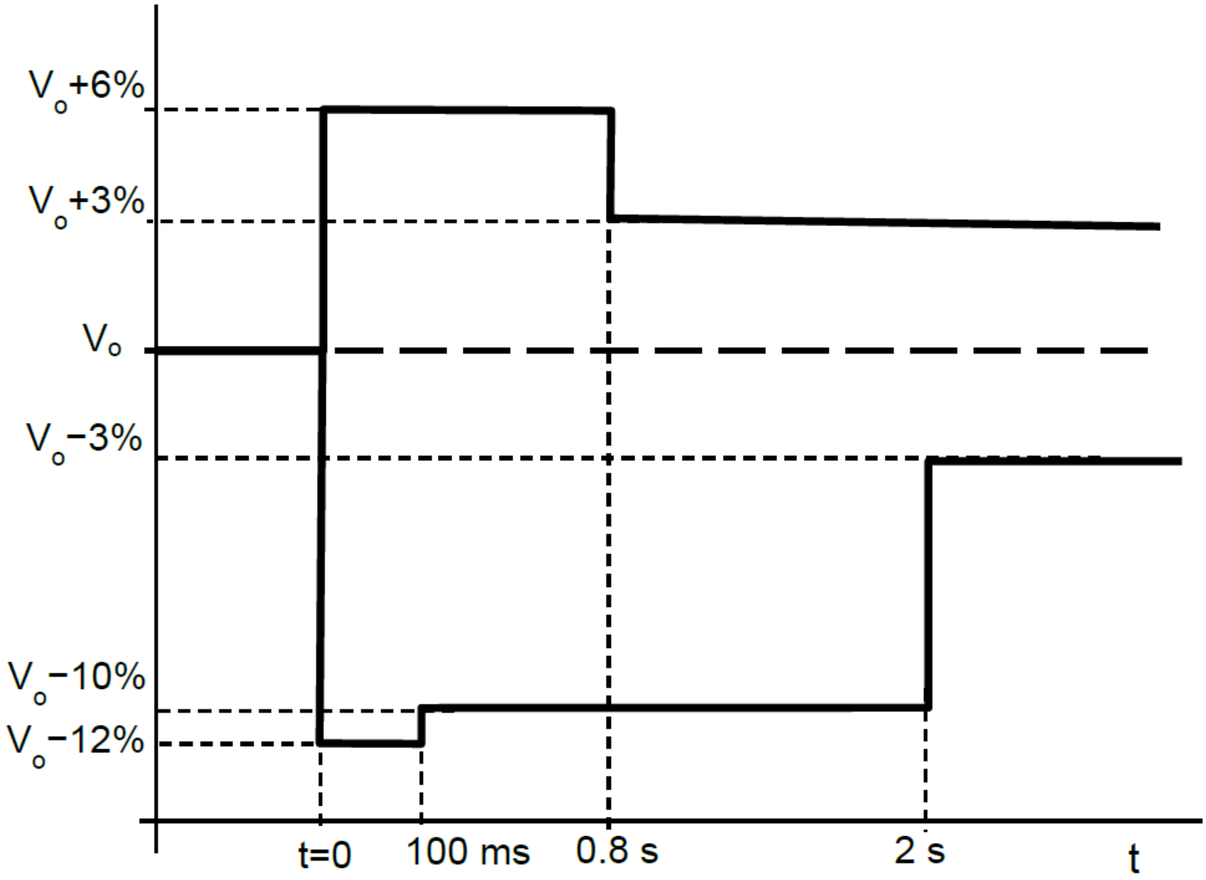


Figure 7 — Voltage characteristic for very infrequent events (Category 3)

4.2.13 The limits for RVCs proposed in EREC P28 Issue 2 take into account those in the recent GC0076 modification to the Grid Code.. It should be noted that the intention is to align the requirements in the Grid Code with those in EREC P28 Issue 2, which will provide greater flexibility for customer connections and will be less onerous to comply with for customers. The key differences between the requirements in EREC P28 Issue 2 and those in the Grid Code are as follows:

- Allowable voltage changes are expressed as a percentage of nominal voltage (V_n) in P28 Issue 2 as opposed to a percentage of the initial voltage (V_o) in the Grid Code. The intention being to align with the approach taken in National and International Standards.
- For increases in voltage:
  - o EREC P28 Issue 2 proposes a limit on the maximum voltage change between two steady state conditions of $\Delta V_{max} \leq 6\%$ for a maximum duration of 0.8 s from the initiation of a voltage change.
  - o The Grid Code has a limit of $\Delta V_{max} \leq 5\%$ for a maximum duration of 0.5 s.
- For decreases in voltage:
  - o EREC P28 Issue 2 proposes a time limit of 100 ms from initiation of a

voltage change during which the maximum voltage change permitted (-12% for ‘very infrequent events’ and -10% for ‘infrequent events’) can persist.

  - The Grid Code has a time limit of 80 ms from initiation of a voltage change during which the maximum permitted voltage change is -12%.

- For increases and decreases in voltage, EREC P28 Issue 2 permits a greater maximum number of occurrences for Category 3 ‘very infrequent’ events:

  - EREC P28 Issue 2 proposes to permit up to a maximum of 4 RVCs in one day (irrespective of type of operational event causing the RVC) not more frequent than once every 3 months.

  - The Grid Code permits up to a maximum of 4 RVCs in one day (for commissioning, maintenance and fault restoration) typically not planned more than once per year on average over the lifetime of the connection.

- EREC P28 Issue 2 introduces an intermediate category of RVC (Category 2) for ‘infrequent events’, where up to a maximum of 4 RVCs in one day are permitted not more frequent than 4 times per month providing the $\Delta V_{max} \leq -10\%$ for ≤ 100 ms then reducing to ≤ 6% for up to 2 s after initiation of the event (see Figure 6).

4.2.14 Table 4, is replicated from EREC P28 Issue 2, which summarises the proposed categories, maximum number of occurrences within a defined time period, limits and examples of applicability for RVCs.

4.2.15 The proposed RVC limits in EREC P28 Issue 2 (and associated differences with the requirements in the Grid Code) reflect the:

- further work carried out by the Working Group and the experience of National Grid in applying RVC limits since the GC0076 modification was implemented in the Grid Code;

- limits for RVCs in Category 2 and Category 3 of Table 4 taking into account differences in the perceptibility of RVC compared with flicker associated with continuously fluctuating loads.

4.2.16 These proposals allow for a greater number of RVCs at any point in the system in a given calendar year on the basis they would be required to either be completed within a 2-hour time window or would be sufficiently spaced apart so as not to result in unacceptable disturbance. Such a modification is intended to facilitate disconnection and reconnection of complete customer sites with significant numbers of transformers for infrequent or very infrequent switching operations, including unplanned outages, with the ability to re-establish distributed generation more quickly after an unplanned outage, e.g. fault outage.

NOTE: DPC4.2.3.3 of the existing Distribution Code places a restriction of not more than one switching event per year for a single voltage change event up to 10% in magnitude. The proposal is to replace this code requirement with the planning levels for RVC in EREC P28 Issue 2.

4.2.17 The Working Group agreed that transformer magnetising inrush should be addressed in the scope of EREC P28 Issue 2. Provision for a simplified assessment of the magnitude of voltage dip caused by transformer energisation is now included in EREC P28 Issue 2. Similarly, the Working Group has provided guidance on the application of EREC P28 and data requirements for use in models/calculations of flicker severity and RVC. The intention is to highlight the sensitivity of voltage fluctuations to certain parameters and initial conditions used.Table 4 — Planning levels for RVC

Cat-egory	Title	Maximum number of occurrence	Limits $\%\Delta V_{max}$ & $\%\Delta V_{steadystate}$	Example Applicability
1	Frequent events	(see NOTE 1)	As per Figure 5	Any single or repetitive RVC that falls inside Figure 5
2	Infrequent events	4 events in 1 calendar month (see NOTE 2)	As per Figure 6 $\lvert \%\Delta V_{steadystate} \rvert \leq 3\%$ For decrease in voltage: $\lvert \%\Delta V_{max} \rvert \leq 10\%$ (see NOTE 3) For increase in voltage: $\lvert \%\Delta V_{max} \rvert \leq 6\%$ (see NOTE 4)	Infrequent motor starting, transformer energisation, G59 [4] re-energisation (see NOTE 7)
3	Very infrequent events	1 event in 3 calendar months (see NOTE 2)	As per Figure 7 $\lvert \%\Delta V_{steadystate} \rvert \leq 3\%$ For decrease in voltage: $\lvert \%\Delta V_{max} \rvert \leq 12\%$ (see NOTE 5) For increase in voltage: $\lvert \%\Delta V_{max} \rvert \leq 6\%$ (see NOTE 6)	Commissioning, maintenance & post fault switching (see NOTE 7)

NOTE 1: ±6% is permissible for 100 ms reduced to ±3% thereafter as per Figure 5.
If the profile of repetitive voltage change(s) falls within the envelope given in Figure 5, the assessment of such voltage change(s) shall be undertaken according to the recommendations for assessment of flicker and shall conform to the planning levels provided for flicker.
If any part of the voltage change(s) falls outside the envelope given in Figure 5, the assessment of such voltage changes, repetitive or not, shall be done according to the guidance and limits for RVCs.

NOTE 2: No more than 1 event is permitted per day, consisting of up to 4 RVCs, each separated by at least 10 minutes with all switching completed within a two-hour window.

NOTE 3: −10% is permissible for 100 ms reduced to -6% until 2 s then reduced to -3% thereafter as per Figure 6.

NOTE 4: +6% is permissible for 0.8 s from the instant the event begins then reduced to +3% thereafter as per Figure 6.

NOTE 5: −12% is permissible for 100 ms reduced to −10% until 2 s then reduced to -3% thereafter as per Figure 7.

NOTE 6: +6% is permissible for 0.8 s from the instant the event begins then reduced to +3% thereafter as per Figure 7.

NOTE 7: These are examples only. Customers may opt to conform to the limits of another category providing the frequency of occurrence does not exceed the 'Maximum frequency of occurrence' for the chosen category.

Allocation of rights (Apportionment)

4.2.18 There was no evidence that the current ‘first-come, first-served’ approach in EREC P28 Issue 1 has resulted in any particular problems for stakeholders, e.g. voltage complaints, flicker headroom being used up.

4.2.19 Notwithstanding, the Working Group considered whether allocating flicker headroom for Stage 3 assessment, as described in PD/IEC/TR 61000-3-7, would be potentially simpler and fairer than the current approach. The pros and cons for maintaining the status quo versus a change in approach were considered. The Working Group concluded that there was no clear merit or justification for changing the ‘first come first served approach’, in particular given the low number of Stage 3 assessments carried out. The decision to retain the current policy of ‘first come first served’ was based on the following.

a) There is no compelling evidence to date that shows there are significant issues with the current ‘first come first served policy’ in practice; the application of the allocation method would appear to be a solution looking for a problem that doesn’t exist.

b) Experience in other countries that have adopted the allocation method in PD IEC/TR 61000-3-7, including Australia, suggests there are complexities and problems with applying it in practice, particularly to existing networks, and that a modified approach based on measurement of flicker background levels and allocation based on available headroom is required to address the short comings.

c) The allocation approach appears to have been taken up more in relation to transmission system operators than for distribution network operators, where there are a greater number of connections.

d) There are fairness arguments for both methods and it would be incorrect to say that the current ’first come first served’ method could be considered to be overwhelmingly unfair. There is not a compelling case to move to the allocation method on the grounds of fairness.

e) A move to an allocation method will be more complex technically and marginally more expensive commercially given that it will require more information and consideration for network operators and connectees than at present.

Background Measurements

4.2.20 The Working Group has now included guidance on background levels for flicker assessment, particularly where there is no measured data. In the absence of any data the flicker background level can be assumed to be P_{st} = 0.5 unless there is reason to believe the flicker background level might be greater than this value, in which case a direct site measurement should be carried out for the purposes of assessment.

4.2.21 The application of transfer coefficients in EREC P28 Issue 2 by the Working Group allows flicker background levels for new substations to be estimated from measurements at other locations in the electricity supply system by applying relevant transfer coefficients from adjacent nodes (see Table 3 of EREC P28 Issue 2 for typical transfer coefficients).

4.3 Changes to network codes

4.3.1 The impact of European Network Codes on EREC P28 was evaluated by the Working Group and no particular issues or conflicts were identified.

4.3.2 The Working Group recognised that EREC P28 Issue 1 provides somewhat contradictory statements with regards to which fault level should be used in Stage 2 and 3 assessments. In particular, whether planned outages of the system should be considered. The Working Group agreed that clear definitions of what should constitute normal operating conditions for assessment, should be provided including how credible outage conditions should be assessed.

4.3.3 Consequently, EREC P28 Issue 2 has been amended to provide improved clarity for the assessment of voltage fluctuations under the 'worst case normal operating condition' (see Clause 6.1.6 of EREC P28 Issue 2), which broadly aligns with the approach in PD IEC/TR 61000-3-7. Normal operating conditions for the supply system are now defined as those operating conditions, where the system/network is designed to operate and remain within acceptable/statutory limits. Table 6 of EREC P28 Issue 2 lists what should be considered normal operating conditions. These conditions include credible outage conditions (both planned and/or fault outages) consistent with securing demand as required by relevant security of supply standards, i.e. ENA Engineering Recommendation P2 for HV distribution networks and National Electricity Transmission System Security Quality of Supply Standards (NETS SQSS) for transmission systems. Notwithstanding, the limits in EREC P28 Issue 2 are not intended to apply to transient voltage fluctuations between fault initiation and fault clearance or during any reconfiguration of the public electricity supply system immediately following a fault to secure supplies.

4.3.4 The Working Group believe the improved definition of normal operating conditions in EREC P28 Issue 2 will provide a more consistent understanding and application of the network conditions by customers and system/network operators for EREC P28 type assessments and will address the lack of definition in the current EREC P28 Issue 1, which is not particularly clear in this respect and is open to interpretation. The Working Group believe the definition of normal operating conditions in EREC P28 Issue 2 are not unduly conservative and formalise good practices with respect to assessing voltage fluctuation.

4.4 Changes in connections and lighting technology

4.4.1 Although for a given voltage disturbance, illuminance variation may be less and therefore flicker may be less perceptible for certain types of modern lighting compared with traditional tungsten filament light bulbs, this response is not universal across all types of lighting technology. On this basis, the Working Group agreed that evaluation of flicker severity in EREC P28 Issue 2 should still be based on the standard flickermeter defined in IEC 61000-4-15 given there is insufficient evidence or industry consensus at present to adopt any changes to the design or function of the standard flickermeter.

4.4.2 The Working Group considered the assessment of LV equipment falling within the scope of BS EN 61000-3-11, where the customer is required to confirm that the network has sufficiently low impedance. After considerable discussions by the

Working Group the output was a revised Stage 1 assessment process in EREC P28 Issue 2, which provides the equipment manufacturer and customer with guidance and approaches to determining the value of supply system impedance and assessing whether this is sufficiently low for connection of equipment with a value of Z_{max} declared by the manufacturer.

4.4.3 The Working Group reviewed the process for assessing LV equipment subject to BS EN 61000-3-3, which is intended for unconditional connection. Although, this standard allows higher flicker levels than the EREC P28 Stage 2 limit at the supply terminals, the Working Group did not find any evidence that unconditional connection of multiple installations of similar equipment under Stage 1 in EREC P28 Issue 2 would pose an unacceptable risk of LV compatibility levels being exceeded at the point of common coupling, providing such equipment conforms to BS EN 61000-3-3 and is independently controlled. Guidance on this aspect is provided in Clause 6.3.2 of EREC P28 Issue 2.

4.5 Improved definition of voltage step change

4.5.1 The Working Group discussed the appropriateness of the general limit on the magnitude of voltage step changes of ±3%. The Working Group believes that this should not be changed to minimise the risk that voltage fluctuations will exceed statutory voltage limits.

4.5.2 However, EREC P28 Issue 2 now clarifies that the ±3% general limit relates to the voltage change between steady state conditions, referred to as $V_{steadystate}$, (see Clause 4.7 of EREC P28 Issue 2). Although EREC P28 Issue 2 does not place a limit on the time for transient decay, it requires that voltage changes must be within ±3% after 2 s from event initiation.

NOTE: Limits for voltage fluctuations in between steady state conditions (referred to as V_{max}) can be greater than ±3% for infrequent events and very infrequent events and fall under requirements for Rapid Voltage Changes in EREC P28 Issue 2.

4.5.3 The intention of this proposal is to allow a clear distinction between distinct different voltage change events.

4.5.4 EREC P28 Issue 1 was not clear whether voltage fluctuation was expressed as a percentage of the initial voltage (V_o) or the nominal voltage (V_n) of the system concerned. The Working Group discussed the need to provide clarity and agreed to align with the approach in the BS EN 61000 series of Standards, where the philosophy is to express voltage changes as a percentage of V_n. Analysis carried out by the Work Group confirms this is not expected to have a material impact on the voltage change limits in EREC P28.

5. Consultation Responses

Responses received from the Public Consultation

5.1 A Distribution Code public consultation took place from the 8th January 2018 to 31st January 2018 on the proposed modification to Engineering Recommendation P28. Industry stakeholders were invited to respond expressing their views or providing any further evidence on any of the matters contained within the consultation document together with the rationale for their responses to the following questions.

Q1 Do you agree with the proposed requirements and planning levels for RVCs in EREC P28 Issue 2 (as provided in Figure 5, Figure 6, Figure 7 and Table 4 of EREC P28 Issue 2)?

Q2 Do you agree with the proposal for providing improved clarity of what constitutes 'worst case normal operating conditions' for the assessment of voltage fluctuations under EREC P28?

Q3 Do you agree with the proposals for an intermediate planning level to assist with co-ordination of the transfer of flicker severity from higher voltage to lower voltage supply systems?

Q4 Do you have any objections to the proposed amendments in EREC P28 Issue 2 as they currently stand? If so, please describe your concerns and if possible propose any alternatives.

Q5 Do you agree that the proposed modification proposal better facilitates the Distribution Code objectives?

Q6 Recognising that any consequential changes to the Grid Code will need to be progressed via the Grid Code governance process, the Working Group would welcome any concerns you have at this stage if the EREC P28 Issue 2 proposal was to be considered for adoption in the Grid Code?

Q7 Do you have any other comments to make on the proposed changes?

5.2 Four responses were received: 1 from a generator stakeholder, 2 from renewable energy stakeholders and 1 from a network operator stakeholder. A summary of the responses received and the subsequent response by the Working Group can be found in Annex 9.3 to this report.

5.3 Two of the four respondents were fully supportive of the proposals and had no objections to the proposed amendments in EREC P28 Issue 2 as they currently stand.

5.4 All four respondents agreed that the modification proposal better facilitates the Distribution Code objectives (see Question 5).

5.5 All four respondents also agreed with the proposals for providing improved clarity of what constitutes 'worst case normal operating conditions' (see Question 2) and the proposals for an intermediate planning level to assist with co-ordination of the transfer of flicker severity from higher voltage to lower voltage supply systems (see Question 3).

5.6 However, two of the respondents provided extensive comments in relation to the proposed requirements and planning levels for RVCs as provided in Figure 5, Figure

6, Figure 7 and Table 4 of EREC P28 Issue 2 (see Question 1). The responses to Question 1 related to the following.

a) The apparent setting of planning levels the same as operating levels for the higher categories of RVCs concerned one respondent because when the network is not operating correctly, equipment could be constrained off for long periods due to external events causing them to trip off.

   i) In response the Working Group believe there would be no realistic prospect of operation of the G59 undervoltage stage 1 protection for external RVC events that conform with the limits and requirements of EREC P28 Issue 2. Furthermore, the reference to "Commissioning, maintenance and post fault switching" in Table 4 of EREC P28 Issue 2 is an example of applicability. NOTE 7 in Table 4 states that these are examples only and that customers may opt to conform to the limits of another category providing the expected frequency of the events do not exceed the maximum frequency permitted for the chosen category. Commissioning, maintenance or post fault switching activities could be classed as Category 1, Category 2 or Category 3 events depending upon the maximum number of occurrences foreseen for those events.

   Subsequent to their initial response the Working Group would point out that Table 4 of EREC P28 Issue 2 refers to planning levels for RVCs, which should be used for design and planning of connections. Whilst design pre-connection should be based on an <u>expected</u> number of both planned and unplanned RVCs over specified time periods to comply with Table 4, it is recognised that Users do not have control of the number of <u>actual</u> unplanned RVC events, including G59 trips, that could occur post connection.

b) One respondent believes that the requirements in Table 4 of EREC P28 Issue 2 are more onerous than CC.6.1.7 of the Grid Code under certain circumstances and that designing for the maximum number of occurrences permitted for Category 2 and Category 3 events in EREC P28 Issue 2 could have cost implications for developers. In addition, that the maximum number of 4 RVCs per day permitted in Category 2 and Category 3 of EREC P28 Issue 2 is impractical for re-energising wind farms based on one wind turbine transformer being energised at a time.

   i) In response, the Working Group do not believe the requirements in EREC P28 Issue 2 are more onerous than Category 2 of Grid Code CC.6.1.7. The time and voltage magnitude limits for Category 3 RVCs shown in Figure CC.6.1.7 of the Grid Code when compared with Figure 7 of EREC P28 Issue 2 confirm that both the time and voltage limits in EREC P28 Issue 2 for Category 3 very infrequent events (not more than 4 RVCs in 1 day providing less frequent than once every 3 calendar months) are less onerous than those for Category 3 RVCs in the Grid Code.

   ii) Regarding the maximum number of 4 RVCs permitted per day under Category 2 and Category 3 of P28 Issue 2. The respondent has assumed only one wind turbine transformer can be energised at a time. EREC P28

Issue 2 does not preclude more than one wind turbine transformer being energised at the same time. The intention of the limits in Category 2 and Category 3 is to allow several transformers to be energised at any one time whilst complying with the applicable limits.

iii) In their response, the Working Group pointed out that the limits in Table 4 of EREC P28 Issue 2 and the associated amendments to the Distribution Code have been carefully chosen to allow a greater number and magnitude of RVC type voltage fluctuations than is currently permitted whilst not posing an unacceptable risk of voltage complaints from other customers connected to the system. It would not be acceptable to increase the RVC limits proposed for Category 2 and Category 3 events in EREC P28 Issue 2 simply to avoid the need for disturbing equipment connectees to mitigate unacceptable voltage fluctuations caused by the energisation of their equipment, where these fluctuations could cause an unacceptable risk of interference to other customers.

iv) The Working Group would also point out that the changes in EREC P28 Issue 2 are a significant relaxation compared with the current requirements in DPC4.2.3.3 of the Distribution Code, which only permits a voltage depression of -10% not more frequently than once per year for energisation of transformers, as a result of post fault switching, post maintenance switching, or carrying out commissioning tests. On this basis, the P28 Working Group is of the opinion that the requirements in Table 4 of EREC P28 Issue 2 should not be relaxed for Category 2 and Category 3 as proposed by the respondent.

5.7 In response to Question 4 concerning any objections to the proposed amendments in EREC P28 Issue 2 as they currently stand.

a) Both respondents referred to their response in Question 1 concerning the proposed requirements and planning levels for RVCs.

5.8 In response to Question 6 concerning the adoption of EREC P28 Issue 2 requirements into the Grid Code.

a) One respondent was concerned that assets could be sitting for long periods of time without generating power as indicated in answer to Q1 representing a major loss of revenue for a windfarm owner/developer.

i) The Working Group believes that the limits and maximum number of occurrences for rapid voltages changes permitted in EREC P28 Issue 2 are less onerous than those in the Grid Code. The intention of the planning levels for rapid voltage changes in EREC P28 Issue 2 are to provide more flexibility for generators, who need to energise large numbers of wind turbine transformers, than currently exists in the Grid Code. The Working Group trusts that their response to Q1 allays these concerns and that there would be no objection to ultimately adopting the relevant limits and requirements from EREC P28 Issue 2 in the Grid Code.

b) Another respondent was concerned that the categories in Table 4 of EREC P28 Issue 2 are different to those in CC.6.1.7 of the Grid Code, which could cause confusion. In particular that the permitted frequency of events for Category 3 in Table 4 of EREC P28 Issue 2 appears to be more onerous than CC.6.1.7 of the Grid Code.

   i) The response from the Working Group highlights that although the categories of RVC events in EREC P28 Issue 2 and the Grid Code have similar numbers, e.g. 'Category 3', the titles, maximum number of occurrences and limits are different. This reflects the further work carried out by the Working Group and the experience of National Grid in applying RVC limits since the GC0076 modification was implemented in the Grid Code. Notwithstanding, the intention is to align the categories in the Grid Code with those in EREC P28 Issue 2, which would avoid confusion.

   ii) With respect to Category 2 and Category 3 events in EREC P28 Issue 2: Under both Category 2 & Category 3, one event is permitted in a given day, where one event can consist of up to 4 separate RVCs (see NOTE 2 of Table 4). Therefore, up to 4 RVCs in a given day are allowed under both Category 2 & Category 3 of Table 4 [EREC P28 Issue 2], which is similar to the maximum of 4 RVCs per day permitted in Category 3 of the Grid Code. The difference being that the permitted occurrence of RVC events in EREC P28 Issue 2 is more frequent (less onerous) than Category 3 of the Grid Code. Category 3 of the Grid Code permits a maximum of 4 RVCs per day typically not planned more than once per year on average over the lifetime of a connection compared with 4 events (each event consisting of up to 4 RVCs) per calendar month for Category 2 events in EREC P28 Issue 2 and 1 event (consisting of up to 4 RVCs) every 3 calendar months for Category 3 events in EREC P28 Issue 2. On this basis the Working Group believes that EREC P28 Issue 2 provides for a greater number of RVCs in any given time period than is currently permitted in the Grid Code. The intention is to provide Users, including generators, with more flexibility for energising transformers than currently exists in the Grid Code.

c) A respondent was concerned that limits for the maximum number of occurrences over a particular time period as stated in Table 4 of EREC P28 Issue 2 appear to be more stringent than those in CC.6.1.7 of the Grid Code and do not allow for operational problems. The wording in CC.6.1.7 states: "…typically not planned more than once per year on average…", whereas EREC P28 Issue 2 does not have such wording.

   i) With respect to the application of the wording "…typically not planned more than once per year on average over the lifetime of a connection…" in CC.6.1.7 (a) (viii) of the Grid Code. The Working Group believes the limits and maximum number of occurrences for RVCs in the Grid Code apply to both design and operation of the system. Although the requirements in EREC P28 Issue 2 primarily relate to the design and assessment of connections, the P28 Working Group does not intend for any particular difference in the application of associated aspects of EREC P28 Issue 2 and the Grid Code. The P28 Working Group would point out that EREC P28 Issue 2 acknowledges that the final decision as to whether or not disturbing equipment exceeding the limits in EREC P28 Issue 2 may be connected to the system is at the discretion of the relevant system/network operator (see Lines 276-280) in EREC P28 Issue 2.

a. Subsequent to their initial response the Working Group would like to clarify that EREC P28 Issue 2 is a planning document. Whilst design at the pre-connection stage should be based on an expected number of both planned and unplanned RVCs over specified time periods to comply with planning levels in Table 4, it is recognised that Users do not have control of the actual number of unplanned RVC events, including G59 trips, that could occur post connection; these could be greater in number than the expected number allowed for in the design. Table 4 of EREC P28 Issue 2 does not restrict the number of unplanned events that happen post-connection in the network, given network Users cannot control these events, e.g. where G59 protection trips due to voltage or frequency events in the network. However, if the number of actual events proves to be unacceptable to other network Users to the extent that 'interference' is caused then the system/network operator would be required to act under Regulation 26 of the Electricity Safety Quality & Continuity Regulation (ESQCR) and may judge that mitigation is needed in a reasonable time period.

5.9 In response to Question 7 concerning any other comments:

a) One respondent commented that is surprising after the description in the introduction [EREC P28 Issue 2] of the importance for restricting flicker to stop customer annoyance and complaints that the same requirements do not apply to all equipment by exempting licenced Distribution and Transmission Operators, given their equipment will be very similar.

i) In response the Working Group pointed out that the scope of EREC P28 Issue 1 applies to voltage fluctuations caused by industrial, commercial and domestic equipment connected to the system. The terms of reference for the revision of EREC P28 Issue 1, as set by the Joint Distribution Code and Grid Code Review Panels, was for EREC P28 Issue 2 to remain a 'customer facing' document and for any overarching application of requirements and limits in EREC P28 to be contained within the Distribution Code. Notwithstanding, the Working Group, as part of their Terms of Reference, has sought to be fair and even-handed in the application of requirements taking into account the different operating context and objectives of Users and network operators.

b) The same respondent also noted there is a reference to current version P28 figure 4 in the SQSS and EREC P28 Issue 2 replaces the original figure 4 with figure B.1.2 and asked for confirmation whether these are the same and whether the SQSS will be corrected?

i) The Working Group note the acknowledgment in the SQSS that EREC P28 Issue 1 Figure 4 was used in the derivation of Figure 6.1 ‘Maximum Voltage Step Changes Permitted for Operational Switching’. Figure B.1.2 in EREC P28 Issue 2 is intended to replace Figure 4 in EREC P28 Issue 1 but has been aligned with the current flicker severity curve in Figure A.1 of PD IEC/TR 61000-3-7 – except that the curve has been deliberately capped at a maximum symmetrical step voltage change of 3% once every 475 s. Consequently, the curve in Figure B.1.2 in EREC P28 Issue 2 differs from that in Figure 4 of EREC P28 Issue 1 and Figure 6.1 of the SQSS. The P28 Working Group recommend that Figure 6.1 in the SQSS is reviewed in light of the current flicker severity curve in Figure A.1 of PD IEC/TR 61000-3-7 and the aligned Figure B.1.2 in EREC P28 Issue 2.

Responses received outside the Public Consultation

5.10 A response was received outside the official public consultation process concerning interpretation of Clause 5.4 Step voltage change limit (lines 835-842). The respondent believes the clause might need re-phrasing as, unless it was intended to do so, it currently states that voltage fluctuations greater than 3% in magnitude should not cause interference where the shape of the voltage characteristic is equivalent to a step change less than or equal to 3%. In other words, a voltage fluctuation of 5% should not cause interference if the disturbing equipment is ramped up/down over a period that will correspond to a step change equivalent figure (using the shape factors) of less than 3%.

a) In response, the Working Group would like to clarify that the general limit on the magnitude of voltage step changes is ±3%. This general limit equates to the maximum change in steady state voltage ($V_{steadystate}$) from the initial voltage to the resulting voltage level. For frequent events that need to be assessed for flicker the voltage characteristic should not exceed the envelope in Figure 5 of EREC P28 Issue 2. On this basis a 5% voltage fluctuation that is ramped up/down over a period but it expected to occur frequently would not be acceptable even though the equivalent step voltage change derived using the appropriate shape factor corresponds to an equivalent step voltage change of less than 3%.

In order to avoid misinterpretation with the requirements in EREC P28 Issue 1 it is proposed to delete lines 840 to 842 inclusive of EREC P28 Issue 2

~~Voltage fluctuations greater than 3% in magnitude should not cause interference where the shape of the voltage characteristic is equivalent to a step voltage change less than or equal to 3% (see 6.3.3.4) or is of sufficiently low frequency of occurrence (see 5.2.2).~~

6. Impact & Assessment

6.1 Impact on the Distribution Code and Grid Code

6.1.1 The revision of EREC P28 Issue 2 materially affects DPC4.2.3.2 (Voltage Disturbances) and DPC4.2.3.3 (Voltage Step Changes) of the Distribution Code. The Working Group recommends the changes to the legal text of the Distribution Code, Issue 33 – 01 August 2018 contained in Annex 9.4 of this report.

6.1.2 The Working Group also recommend that the requirements of CC.6.1.7 of the Grid Code are aligned with those in EREC P28 Issue 2. NGET are looking to propose legal text changes to the Grid Code as a separate code modification.

6.2 Impact on Distribution Code Users

6.2.1 The proposed modification provides Users with improved clarity of requirements concerning assessment and measurement of voltage fluctuations, in particular, the definition of what constitutes 'worst case normal operating conditions' for assessments. The respective responsibilities of Users and system/network operators in the assessment process are better defined, which is expected to allow for a more consistent application of EREC P28 requirements by system/network operators.

6.2.2 The proposed planning levels for RVC, whilst allowing for a greater number and magnitude of RVC type voltage fluctuations than is currently permitted is not considered to pose an unacceptable risk of voltage complaints from other Users connected to the system.

6.2.3 The proposal for an intermediate planning level and adjustment of associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV will improve the co-ordination of flicker transfer from higher voltage to lower voltage supply systems. This is expected to reduce the possibility of background flicker severity levels exceeding compatibility limits at LV from the transfer of voltage fluctuations down through the supply system.

6.2.4 The modifications are intended not to unduly impact on or cause interference to existing Users of public electricity systems/networks.

6.3 Impact on embedded generators

6.3.1 The proposed modification to the Distribution Code will allow embedded generators to plan for a greater number of RVCs at any point in the system in a given calendar year than currently exists in EREC P28 Issue 1 and the Distribution Code. The intention of the modification is to facilitate disconnection and reconnection of complete customer sites with significant numbers of transformers for infrequent or very infrequent switching operations, including unplanned outages, with the ability to re-establish distributed generation more quickly after an unplanned outage, e.g. fault outage.

6.4 Impact on National Electricity Transmission System (NETS)

6.4.1 The proposed changes to the RVC voltage envelopes arising from Figure 5, Figure 6 and Figure 7 of EREC P28 Issue 2 are expected to have a minimal impact on the NETS compared with those in CC.6.1.7 of the Grid Code. Under EREC P28 Issue 2 the maximum no. of occurrences of RVCs would change from typically 4 RVCs in one day (for commissioning, maintenance and fault restoration) typically not planned more than once per year on average over the lifetime of the connection to 4 RVCs in one day not more than once per three months. Whilst this increases the number of planned RVCs permitted per year these will be sufficiently spaced apart so as to minimise any potential disturbance to customers connected at point of common couplings No impact is foreseen regarding notification of Category 3 events, which still require notification to NGET.

6.4.2 The NETS SQSS uses EREC P28 Issue 1 Figure 4 in the derivation of Figure 6.1 'Maximum Voltage Step Changes Permitted for Operational Switching'. Figure B.1.2 in EREC P28 Issue 2 replaces Figure 4 in EREC P28 Issue 1 so that the curve has been deliberately capped at a maximum symmetrical step voltage change of 3% once every 475 s compared with once every 600 s previously. The Working Group would recommend that Figure 6.1 in the NETS SQSS is reviewed in light of the current flicker severity curve in Figure A.1 of PD IEC/TR 61000-3-7 and the aligned Figure B.1.2 in EREC P28 Issue 2. If the SQSS were to be subsequently modified on this basis it would permit more voltage step changes of a given magnitude of 3% over a given time period than is currently allowed now.

6.5 Assessment against Distribution Code Objectives

6.5.1 The proposed amendments would better facilitate the following applicable Distribution Code objectives:

(a) permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity.

i) The proposals provide improved clarity of voltage fluctuation requirements for Users wishing to connect to public electricity supply systems. The proposals facilitate improved co-ordination of planning levels for flicker related voltage fluctuations and RVCs down through voltage levels to minimise the risk of compatibility levels being exceeded at LV.

ii) The proposals allow Users to have a greater number and magnitude of RVC type voltage fluctuations over a year than is currently permitted in P28 Issue 1 and the Distribution Code. This provides Users with greater flexibility on how they design their equipment/connection to meet voltage fluctuation limits and how they can avoid costs with providing additional equipment to reduce the magnitude of voltage fluctuations.

(b) facilitate competition in the generation and supply of electricity

i) The proposals are expected to facilitate connection of embedded generation, which may otherwise not be connected to the system because of the limits on the magnitude and number of voltage fluctuation events permitted in DPC.4.2.3.3 of the current issue of the Distribution Code, in relation to the energisation of complete sites with a significant presence of transformers.

(c) efficiently discharge the obligations imposed upon distribution licensees by the distribution licences and comply with the Regulation and any relevant legally binding decision of the European Commission and/or the Agency for the Co-operation of Energy Regulators.

i) The proposals align requirements in EREC P28 Issue 2 with provisions for voltage fluctuations in the relevant series of BS EN 61000 standards. so far as considered relevant and suitable by the Working Group. The proposals are intended to comply with the requirements for voltage fluctuations in the proposed European Network Codes.

(d) promote efficiency in the implementation and administration of the Distribution Code.

i) The proposals allow detailed requirements in DPC.4.2.3.3 of the Distribution Code concerning fluctuations to be addressed in EREC P28 Issue 2. The intention is to avoid any conflict between the Distribution Code and EREC P28.

6.6 Impact on core industry documents

6.6.1 The proposed modifications to EREC P28 and the Distribution Code impacts on requirements in clauses 9.5.7 to 9.5.11 inclusive of Engineering Recommendation G59. These clauses refer to limits and requirements in EREC P28 that have been modified under these proposals. In essence, minor text changes are required to align with EREC P28 Issue 2 as documented in Annex 9.5 - EREC G59 Issue 3 Amendment 4 July 2018 .

6.6.2 In addition, Clause 3.2 of Engineering Recommendation G59 will need to be amended to reflect the modified title of EREC P28 (see Annex 9.5).

6.6.3 As stated in 6.4.2 of this report Figure 6.1 'Maximum Voltage Step Changes Permitted for Operational Switching' in the NETS SQSS is possibly impacted should the decision be taken to align this with the new Figure B.1.2 in EREC P28 Issue 2.

6.6.4 The proposed modification does not affect any other core industry documents other than the Grid Code.

6.7 Implementation

6.7.1 The Working Group confirms there are no reasons why implementation should be unduly delayed and recommends that the proposed changes be implemented from 1st August 2018, or other such date as the Authority might agree to. The proposed date for implementation has been chosen to follow other modifications that pre date EREC P28 Issue 2 and to coincide with proposed Issue 33 of the Distribution Code.

6.7.2 In accordance with DGC11.2 of the Distribution Code:

(a) the proposed changes in EREC P28 Issue 2 are not intended to apply retrospectively to equipment already existing at the date of implementation of the Distribution Code change.

(b) any material changes to Equipment after the date of implementation will need to comply with the requirements of EREC P28 Issue 2.

7. Working Group Recommendations

7.1 The recommendations of the Working Group are as follows.

a) EREC P28 Issue 2 as it was consulted upon (see Annex 9.2 'ENA_EREC_P28_Issue 2_2017_Final Draft_v3.5_Issued') is accepted subject to the following specific amendments.

The following proposed amendments i), ii) and iii) arising from the public consultation (as documented in 'ENA_EREC_P28_Issue 2_2017_Final Draft_v3.6_Issued').

i) Clause 5.3.2 Planning Levels (Line 765-767):

"The planning levels in Table 4 define absolute limits of maximum voltage change (ΔV_{max}) and steady state voltage change ($\Delta V_{steadystate}$) for RVCs according to the maximum number of occurrences ~~permitted~~ expected within a specified time period."

ii) Table 4 Note 7:

"These are examples only. Customers may opt to conform to the limits of another category providing the frequency of occurrence ~~does~~ is not expected to exceed the 'Maximum frequency of occurrence' for the chosen category."

iii) Clause 5.4 Step voltage change limit (Lines 840-842)
~~"Voltage fluctuations greater than 3% in magnitude should not cause interference where the shape of the voltage characteristic is equivalent to a step voltage change less than or equal to 3% (see 6.3.3.4) or is of sufficiently low frequency of occurrence (see 5.2.2)."~~

The following additional amendment iv) proposed below arising from the meeting of the Distribution Code Review Panel (DCRP) held on 05/04/2018 (as documented in 'ENA_EREC_P28_Issue 2_2017_Final Draft_v3.7_Issued' – See Annex 9.7).

iv) Table 4 Note 7:

Addition of the following sentence at the end of the proposed note: "Where the measured emission level exceeds the expected emission level, paragraph 4 of Clause 6.1.4 applies."

b) The proposed requirements and planning levels for RVCs in EREC P28 Issue 2 (as provided in Figure 5, Figure 6, Figure 7 and Table 4 of EREC P28 Issue 2) are implemented.

c) The definition of 'worst case normal operating conditions' and associated requirements for assessing these conditions in EREC P28 Issue 2 are accepted.

d) The intermediate planning level and associated flicker severity limits for supply systems with nominal voltages of 3.3 kV, 6.6 kV, 11 kV, 20 kV and 33 kV is accepted to improve the transfer of flicker severity from higher voltage to lower voltage supply systems.

e) The proposed changes to the legal text of the Distribution Code, Issue 33 – 01 August 2018 as documented in Annex 9.4 and 9.4.1 to this report are implemented.

f) The relevant clauses in Engineering Recommendation G59 that refer to limits and requirements in EREC P28 are aligned with the proposed amendments in EREC P28 Issue 2 as documented in Annex 9.5 - EREC G59 Issue 3 Amendment 4 July 2018.

g) It is recommended that the Grid Code Review Panel draft and progress proposed changes to the legal text of the Grid Code via the Grid Code governance process to align with the proposals in EREC P28 Issue 2.

h) It is recommended that the SQSS Review Panel review Figure 6.1 in the NETS SQSS in light of the current flicker severity curve in Figure A.1 of PD IEC/TR 61000-3-7 and the aligned Figure B.1.2 in EREC P28 Issue 2.

8. Distribution Code Review Panel Recommendation

8.1 At the meeting of the Distribution Code Review Panel (the Panel) held on 05/04/2018, a number of clarifications on the Report to Authority were requested. Subsequently, the Panel were consulted via email (09/05/18) on a small number of amendments. The Panel members subsequently responded indicating they were content with the amendments and therefore agreed to the submission of this amended Report to Authority and the Final amended version of P28 Issue 2 (Annex 9.7 - ENA_EREC_P28_Issue 2_2017_Final Draft_v3.7_Issued') as the Panel agreed that the Modification proposal better facilitated the objectives of the Distribution Code.

9. Annexes

9.1 Working Group Terms of Reference

Please see the separate attachment to this report titled 'Annex 9.1_DCRP/MP/18/01/RtA'

9.2 Public Consultation Pack for Revision of EREC P28

Please see the separate attachment to this report titled 'Annex 9.2_DCRP/MP/18/01/RtA'

9.3 Responses to the Public Consultation for Revision of EREC P28

Please see the separate attachment to this report titled 'Annex 9.3_DCRP/MP/18/01/RtA'

9.4 Proposed changes to the legal text of the Distribution Code

Please see the separate attachment to this report titled 'Annex 9.4_DCRP/MP/18/01/RtA'

9.4.1 Revised draft Distribution Code V33 (with the changes referenced in 9.4)

Please see the separate attachment to this report titled 'Annex 9.4.1_DCRP/MPPC/18/01/RtA'

9.5 Proposed changes to the legal text of EREC G59 Issue 3 Amendment 4 July 2018

Please see the separate attachment to this report titled ‘Annex 9.6_DCRP/MP/18/01/RtA’

9.6 Final amended version of EREC P28 Issue 2 for approval by the Authority

Please see the separate attachment to this report titled ‘Annex 9.7_DCRP/MP/18/01/RtA’

PRODUCED BY THE OPERATIONS DIRECTORATE OF ENERGY NETWORKS ASSOCIATION

Engineering Recommendation P28

Issue 2 2018

Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom

www.energynetworks.org

PUBLISHING AND COPYRIGHT INFORMATION

Operations Directorate
Energy Networks Association
6th Floor, Dean Bradley House
52 Horseferry Rd
London
SW1P 2AF

First published as Issue 1, 1989

Revised and published as Issue 2, 2018

Amendments since publication

Issue	Date	Amendment
2	2018	Major technical revision

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Foreword

This Engineering Recommendation (EREC) is published by the Energy Networks Association (ENA) and comes into effect from date of publication. The approved abbreviated title of this Engineering Recommendation is "EREC P28", which replaces the previously used abbreviation "ER P28".

Revision of this EREC has been prepared under the authority of the Grid Code and Distribution Code Review Panels of Great Britain – being a qualifying standard and licence standard under these respective codes. The review and subsequent revision of EREC P28 has been overseen by the ENA P28 Working Group. Approval for publication has been granted by Ofgem.

This EREC supersedes ENA Engineering Recommendation P28 Issue 1 1989.

This EREC has been fully updated with reference to the United Kingdom implementation of the IEC 61000 series of Standards so far as they relate to voltage fluctuations and disturbance.

Harmonic voltage distortion and voltage unbalance aspects associated with the connection of disturbing equipment to transmission systems and distribution networks are covered in ENA Engineering Recommendation G5 and Engineering Recommendation P29 respectively.

This document constitutes a full technical revision of EREC P28 Issue 1. This issue [Issue 2] of EREC P28 has been extended to cover assessment and limits for rapid voltage changes (RVCs).

This EREC is intended to be read as a standalone document; references to other publications are intended to direct users to additional supporting information that could be useful but not essential to understanding requirements.

Engineering Report P28 [8] provides background, information and examples that support the requirements in this EREC.

This EREC should be used by those who propose to connect disturbing equipment with the potential for voltage fluctuation, being flicker and/or RVC, to public electricity supply systems. The document should also be used by those who carry out assessments concerning the suitability of connecting such equipment to these systems.

This document is not intended to replace or override requirements in BS EN 50160 for ensuring acceptable voltage quality.

The terms 'this Engineering Recommendation' and 'this EREC' refer to Engineering Recommendation P28 Issue 2 2018, as amended.

In this document, the term 'shall' relates to a statutory or mandatory requirement. The term 'should' expresses a recommendation and the term 'may' indicates a permission.

Commentary, explanation and general informative material is presented in smaller *italic* type, and does not constitute a normative element.

The term ‘system/network operator’ in this EREC is intended to apply to owners and operators of transmission systems and distribution networks, in so far as the requirements are applicable to their statutory and regulatory duties and responsibilities.

The term ‘disturbing equipment’ is intended to refer to individual items of disturbing equipment, whereas the term ‘fluctuating installation’ is intended to refer to multiple items of disturbing equipment contained within an installation connected to the supply system.

The convention used for cross-referencing clauses within this EREC is the omission of the term ‘clause’ before the clause number and the placing within parenthesis. For example: “(see 5.3)” denotes a cross-reference to Clause 5.3 in this document.

Abbreviations used throughout this document are stated in ‘Terms and definitions’ (see 3).

Introduction

Repetitive voltage fluctuations of sufficient frequency and/or magnitude in the supply system can cause the luminance of incandescent lamps, e.g. traditional tungsten filament light bulbs, to fluctuate with time. This creates an impression of unsteadiness of visual sensation in humans, who observe these fluctuations. This effect is known as flicker. If the flicker is of sufficient severity then this can be annoying to observers and can result in them complaining to the system/network operator.

Fast changes in supply system voltages can result from energising/de-energising certain types of electrical equipment. These are known as rapid voltage changes (RVCs) which, if of sufficient magnitude, duration and frequency, can cause maloperation of and damage to equipment and similar annoyance, as flicker, to those that observe changes in luminance of electric lighting. The process for assessment of RVCs is described in Clause 5.3.

EREC P28 was first published in 1989 to provide recommended planning limits for voltage fluctuations for connection of equipment to public electricity supply systems in the UK. Issue 1 was primarily concerned with assessment of voltage fluctuations and associated flicker produced by traditional domestic, commercial and industrial loads. Since EREC P28 was first published, the factors affecting development of transmission systems and distribution networks, and equipment connected to them have changed significantly. There has been a shift towards connection of distributed/embedded generation equipment powered by renewable energies and other low carbon technology equipment. These types of modern equipment are capable of causing flicker. As such, the impact of connecting modern equipment has been reviewed and EREC P28 has been updated accordingly.

Significant developments in Electromagnetic Compatibility (EMC) requirements have taken place, which are captured in the International Electrotechnical Commission (IEC) 61000 series of Standards and technical reports. United Kingdom implementation of these Standards is captured in the various parts of BS EN 61000. Consequently, EREC P28 Issue 2 has been revised in line with the requirements of these Standards, so far as they apply to the limitation of voltage fluctuations in public electricity supply systems and resultant flicker. Relevant considerations in IEC technical reports have been reviewed and, where appropriate, have been adopted.

The flickermeter algorithm is based on the perceived visual effects from traditional incandescent light bulbs, which are being phased out and replaced by new technology lamps including:

- halogen;
- compact fluorescent lamps (CFL);
- light emitting diodes (LED).

Whilst most new technology lamps are less sensitive to applied voltage fluctuations, some are more sensitive at higher frequencies [of voltage fluctuation] than the traditional 60 W incandescent lamp, which is the reference lamp for the flicker curve[1].

For example: some types of high pressure discharge lighting might produce marginally higher levels of flicker severity than tungsten filament lamps at higher frequencies of the voltage fluctuation spectrum, however operating experience over many years has not found this to be problematic. The requirements in this EREC will need to be kept under review given on-going developments in lighting technology.

International Standards continue to use the existing flicker curve [P_{st} = 1 in Figure 2 of BS EN 61000-3-3] for assessing the disturbance to lighting and all other equipment connected to public electricity supply systems caused by voltage fluctuation. The limits for voltage fluctuation in EREC P28 Issue 2 are compatible with the existing flicker curve.

This EREC defines good engineering practice, which is applicable to the connection of customers' disturbing equipment and fluctuating installations, with respect to limiting voltage fluctuations on transmission systems and distribution networks in the United Kingdom.

The intention is that planning levels stated in this EREC will ensure emissions from new connections of customers' disturbing equipment and fluctuating installations are sufficiently below immunity levels of equipment connected to the system so as not to cause unacceptable disturbance to other customers and system users. Disturbance includes the effect of voltage fluctuations on flicker severity and/or the capability of equipment connected to the system to function correctly. The planning levels in this document should not be considered as targets and all reasonable steps should be taken to minimise voltage fluctuations.

A key principle in this EREC is that the visual discomfort due to light flicker is the most frequent reason to limit voltage changes due to fluctuating installations. Flicker, if particularly severe, can adversely affect the health of those people exposed. This is why minimising flicker, where possible, is important. System/network operators have to maintain the voltage magnitude within narrow limits and individual customers should not produce significant voltage fluctuations even if they are tolerable from a flicker perspective.

A three-stage approach is presented for assessing the acceptability of the connection of proposed disturbing equipment and/or fluctuating installations, in terms of flicker, to supply systems.

a) Stage 1

The intention is that individual equipment that conforms to relevant product standards can be connected to the system without further assessment under Stage 1 (see 6.3.2).

[1] The term 'flicker curve' relates to the curve for P_{st} = 1 for rectangular equidistant voltage changes as illustrated in Figure 2 of BS EN 61000-3-3. The flicker curve is used to determine the amplitude of rectangular voltage changes that correspond to a flicker severity of P_{st} = 1 for a particular rate of repetition.

b) Stage 2

Disturbing equipment that does not conform to Stage 1 requirements but conforms to limits and requirements in Stage 2 can be connected without detailed assessment or consideration of flicker background level (see 6.3.3).

c) Stage 3

All other disturbing equipment that does not conform to limits and requirements in Stage 2 will need detailed assessment against Stage 3 limits and requirements before it can be connected (see 6.3.4).

The characteristic of flicker means disturbances from independent sources are not directly additive. In practice, additional disturbing equipment/fluctuating installations can generally be connected to the electricity supply system even when the existing flicker background level is approaching the planning level[2]. The coincidence of RVCs from independent sources is considered to present a low enough probability that no summation laws are taken into account when assessing RVCs. Whilst it is recognised that particular network designs could result in coincident RVCs under certain circumstances, e.g. restoration of systems/networks following a G59 trip event, conformance to the limits in this EREC is still required.

Therefore, flicker from disturbing equipment/fluctuating installations should not be unnecessarily constrained by system/network operators, to allow for future unspecified emissions, subject to good engineering practice being followed in the design and installation of disturbing equipment.

If disturbing equipment fails to meet the stage limits following assessment, in exceptional circumstances the system operator or network operator may permit the connection of disturbing equipment even though flicker levels are likely to exceed planning levels. The final decision as to whether or not disturbing equipment exceeding the limits in this EREC may be connected to the public electricity supply system is at the discretion of the relevant system/network operator – subject to any other recourse that could be available to customers[3].

1 Scope

This EREC defines planning levels and compatibility levels for the assessment of voltage fluctuations from customer disturbing equipment and fluctuating installations to be connected to transmission systems and distribution networks in the United Kingdom.

This EREC only applies to the proposed connection of customer disturbing equipment and fluctuating installations. It is not intended to apply to the connection of equipment or installations operated by licensed distribution network operators or licensed transmission system operators.

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[2] A review of flicker background levels in the UK public electricity supply system has not found any evidence to support apportioning of remaining capacity to prevent planning levels being exceeded in future. See ENA Engineering Report P28 [8].

[3] Such as Regulation 26 of The Electricity Safety, Quality & Continuity Regulations 2002 [6] (as amended) for GB and Regulation 27 The Electricity Safety, Quality and Continuity Regulations (Northern Ireland) 2012 [7] (as amended) for Northern Ireland.

The scope of voltage fluctuations in this EREC applies to flicker or RVCs emitted onto the public electricity supply system by customer equipment, i.e. customer owned demand, generation, energy storage[4], or other types of disturbing equipment that may be connected.

This EREC is not intended to be applied retrospectively to existing connections that have been previously assessed under Issue 1 of EREC P28.

However, it is intended to be applied in the event of any change(s) to existing customer disturbing equipment/fluctuating installations that affect voltage fluctuation and to new connections.

This EREC neither replaces nor negates the United Kingdom implementation of EMC Standards, including relevant harmonised equipment Standards that are applicable to particular equipment, under the terms of the Electromagnetic Compatibility Regulations 2016 [1]. The intention is to assist customers to meet their obligations under these Regulations and to prevent interference.

The provisions in this EREC only apply to voltage fluctuations and connection of disturbing equipment. Other criteria, not stated in this document, apply to meeting current ratings, statutory voltage limits, harmonic distortion limits etc. such that, even if voltage fluctuation aspects are satisfied, the connection of disturbing equipment will be conditional on meeting other criteria.

Specific aspects not considered in this EREC include radiated interference, which might affect communications systems, and specific methods for mitigation of disturbances.

2 Normative references

The following referenced documents, in whole or part, are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

Standards publications

IEC 60050, *International Electrotechnical Vocabulary*

IEC TR 61000-2-1, *Electromagnetic compatibility (EMC) - Part 2: Environment - Section 1: Description of the environment - Electromagnetic environment for low-frequency conducted disturbances and signalling in public power supply systems*

IEC 61851-21-1, *Electric vehicle conductive charging system - Part 21-1: Electric vehicle on-board charger EMC requirements for conductive connection to an AC/DC supply*

BS EN 61000-2-2, *Electromagnetic compatibility (EMC). Environment. Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems*

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4 Energy storage installations can operate flexibly as load or generation.

BS EN 61000-3-3, *Electromagnetic compatibility (EMC). Limits. Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems, for equipment with rated current ≤ 16 A per phase and not subject to conditional connection*

BS EN 61000-3-11, *Electromagnetic compatibility (EMC). Limits. Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems. Equipment with rated voltage current ≤ 75 A and subject to conditional connection*

BS EN 61000-4-15, *Electromagnetic compatibility (EMC). Testing and measurement techniques. Flickermeter. Functional and design specifications*

BS EN 61000-6-3, *Electromagnetic compatibility (EMC). Generic standards. Emission standard for residential, commercial and light-industrial environments*

BS EN 61000-6-4, *Electromagnetic compatibility (EMC). Generic standards. Emission standard for industrial environments*

BS EN 61000-4-30, *Electromagnetic compatibility (EMC). Testing and measurement techniques. Power quality measurement methods*

BS EN 61400-21, *Wind turbines. Measurement and assessment of power quality characteristics of grid connected wind turbines*

BS 7671:2008+A3:2015, *Requirements for Electrical Installations. IET Wiring Regulations*

Other publications

[N1] ENA Engineering Recommendation G83, *Recommendations for the connection of type tested small-scale embedded generators (up to 16 A per phase) in parallel with low-voltage distribution systems*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

3.1
compatibility level
specified electromagnetic disturbance level used as a reference level in a specified environment for coordination in the setting of emission and immunity limits

NOTE: By convention, the compatibility level is chosen so that there is only a small probability, for example 5%, that it will be exceeded by the actual disturbance level.

[Equivalent to definition in Clause 3.6 of PD IEC/TR 61000-3-7:2008]

3.2
conditional connection
connection of equipment requiring the customer's supply at the connection point to have an impedance lower than the reference impedance Z_{ref} in order that the equipment emissions conform to the limits in BS EN 61000-3-3

NOTE 1: Meeting the voltage change limits might not be the only condition for connection; emission limits for other phenomena such as harmonics, might also have to be satisfied.

NOTE 2: The symbol Z_{ref} relates to the reference impedance referred to in BS EN 61000-3-3 and BS EN 61000-3-11.

3.3
customer
entity who is or is entitled to either supply or be supplied with electricity at any premises within the United Kingdom excepting the licensed transmission system operator or licensed network operator

NOTE 1: The definition of "customer" broadly aligns with the GB Distribution Code [2] but includes customer own generation by virtue of: "…to either supply or be supplied electricity…".

3.4
distribution network
part of a public electricity supply system that requires the owner or operator to hold a Distribution Licence in the United Kingdom

3.5
disturbance
electromagnetic phenomenon which, by being present in the electromagnetic environment, can cause electrical equipment to depart from its intended performance

3.6
disturbing equipment
equipment that when connected to the public electricity supply system has the potential to cause disturbance from voltage fluctuations

3.7
electricity supply system
lines, switchgear and transformers operating at various voltages which make up the transmission systems and distribution networks to which customers' installations are connected

NOTE 1: Sometimes abbreviated to "supply system" or "system".

NOTE 2: When preceded by the term "public", the wider use of the system is intended.

3.8
electromagnetic compatibility (EMC)
ability of equipment or a system to function satisfactorily in its electromagnetic environment without introducing intolerable electromagnetic disturbances to anything in that environment

NOTE 1: Electromagnetic compatibility is a condition of the electromagnetic environment such that, for every phenomenon, the disturbance emission level is sufficiently low and immunity levels are sufficiently high so that all devices, equipment and systems operate as intended.

NOTE 2: Electromagnetic compatibility is achieved only if emission and immunity levels are controlled such that the immunity levels of the devices, equipment and systems at any location are not exceeded by the disturbance level at that location resulting from the cumulative emissions of all sources and other factors such as circuit impedances. Conventionally, compatibility is said to exist if the probability of the departure from intended performance is sufficiently low. See Clause 4 of BS EN 61000-2-1.

NOTE 3: Where the context requires it, compatibility could be understood to refer to a single disturbance or class of disturbances.

NOTE 4 Electromagnetic compatibility is a term used also to describe the field of study of the adverse electromagnetic effects which devices, equipment and systems undergo from each other or from electromagnetic phenomena.

3.9
emission
source of electromagnetic disturbance

3.10
emission level
level of a given electromagnetic disturbance emitted from a particular device, equipment, system or fluctuating installation as a whole, assessed and measured in a specified manner

3.11
emission limit
maximum emission level specified for a particular device, equipment, system or disturbing installation as a whole

3.12
ENA
Energy Networks Association

NOTE: ENA have responsibility for the review, publication and maintenance of EREC P28.

3.13
equipment
single apparatus or set of devices or apparatuses, or the set of main devices of an installation, or all devices necessary to perform a specific task

3.14
EREC
Engineering Recommendation

3.15
flicker
impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time

NOTE: Flicker is the effect on certain types of electric lamps, in particular incandescent lamps, while the electromagnetic phenomenon causing it is referred as voltage fluctuations.

[Equivalent to definition in Clause 3.6 of PD IEC/TR 61000-3-10:2008].

3.16
fluctuating installation
electrical installation as a whole, i.e. including disturbing equipment and non-disturbing equipment, which is characterized by repeated or sudden power fluctuations, or start-up or inrush currents which can produce flicker or rapid voltage changes on the electricity supply system to which it is connected

3.17
fundamental frequency
frequency in the spectrum obtained from a Fourier transform of a time function, to which all the frequencies of the spectrum are referred.

NOTE: For the purpose of this EREC, the fundamental frequency is the same as the power supply frequency.

[Same as definition in PD IEC/TR 61000-3-7:2008].

3.18
high voltage (HV)
voltage exceeding 1 kV

NOTE: Equivalent to definition in the GB Distribution Code [2].

3.19
IEC
International Electrotechnical Commission

3.20
immunity level
maximum level of a given electromagnetic disturbance on a particular device, equipment or system for which it remains capable of operating with a declared degree of performance

3.21
interference
overlap of system disturbance levels and equipment immunity levels resulting in unwanted effects such as visual discomfort, degradation or maloperation of equipment

3.22
long-term flicker severity (P_{lt})
measure of the visual severity of flicker for a specified period derived from the summation of P_{st} values in accordance with the general formula stated in Clause 4 of PD IEC/TR 61000-3-7

NOTE: A 2 h period is specified in this EREC.

3.23
low voltage (LV)
in relation to alternating current, a voltage exceeding 50 V but not exceeding 1 kV

NOTE: Equivalent to definition in the GB Distribution Code [2].

3.24
network operator
owner or operator of a distribution network

NOTE: The term ‘network operator’ primarily applies to licensed Distribution Network Operators (DNOs) and Independent DNOs in the United Kingdom.

3.25
normal operating conditions
variation of generation/demand, the energisation/de-energisation of plant and equipment as a consequence of temporal, seasonal and operational variability, including credible outages, under which the supply system is designed to operate

NOTE: See Clause 6.1.6.

3.26
planning level
level of a particular disturbance in a particular environment, adopted as a reference value for the limits to be set for the emissions from the installations in a particular system, in order to coordinate those limits with all the limits adopted for equipment and installations intended to be connected to the electricity supply system

[Equivalent to definition in Clause 3.19 of PD IEC/TR 61000-3-7:2008]

3.27
point of common coupling (PCC)
point in the public electricity supply system which is electrically closest to the installation concerned and to which other customers are or might be connected

NOTE: The PCC is generally upstream from the installation concerned.

3.28
protective multiple earthing (PME)
TN-C-S LV supply system

NOTE: The term ‘TN-C-S’ is defined in BS 7671.

3.29
rapid voltage change (RVC)
change in root mean square (r.m.s.) voltage over several cycles

NOTE 1: Rapid voltage changes can also be in the form of cyclic changes.

NOTE 2: See Clause 5.2.

[Similar to definition in PD IEC/TR 61000-3-7:2008].

3.30
service current capacity
the current per phase which can be taken continuously by the customer at their supply terminals without exceeding the plant ratings used by the system/network operator in the design of its system

NOTE: Each part of the LV service equipment that provides the customer connection has a rating, i.e. service cable, cut-out, meter and meter tails. The environment that service equipment is located within affects this rating. In the case of a looped service, the rating is also determined by the service equipment at the adjacent premise(s). Whichever part of the service equipment has the lowest rating defines the service current capacity. It is necessary to consult the network operator to establish the service current capacity. In cases where the network operator declares supply capacities in volt-amperes, the current per phase can be deduced for: single-phase supplies by dividing the volt-amperes by the declared phase-neutral voltage, and three-phase supplies by dividing the volt-amperes by √3 multiplied by the declared phase-phase voltage.

3.31
short-term flicker severity (P_{st})
measure of the visual severity of flicker derived from the time series output of a flickermeter over a 10-minute period

NOTE 1: P_{st} provides an indication of the risk of customer complaints arising from voltage fluctuations.

NOTE 2: P_{st} = 1 for any point on the curve in Figure 2 of BS EN 61000-3-3 (replicated in Annex B) for repetitive and periodic step voltage changes in the form of a square waveform.

NOTE 3: The term ‘flickermeter’ refers to apparatus for measuring flicker conforming to the requirements of BS EN 61000-4-15.

3.32
step voltage change
change from the initial voltage level to the resulting voltage level after all generating unit automatic voltage regulator (AVR) and static VAR compensator (SVC) actions and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced

NOTE 1: Automatic voltage regulator also applies to other similar fast acting voltage control responses, e.g. associated with power park modules, HVDC voltage control responses.

NOTE 2: For the purposes of this EREC, percentage step voltage change is the value of step voltage change in volts expressed as percentage change of the nominal system voltage (V_n).

NOTE 3: Step voltage change can be equivalent to the steady state voltage change ($\Delta V_{steadystate}$) (see 4.6).

NOTE 4: By virtue of this definition, a ramped voltage change can be a form of step voltage change and subject to the limit in Clause 5.4.

NOTE 5: Step voltage changes can occur as a result of switching on the system, a fault or operation of disturbing equipment that produces an instantaneous change in steady state voltage.

[Similar to definition in DPC4.2.3.3 of the GB Distribution Code [2]].

3.33
system operator
owner or operator of a transmission system

3.34
transfer coefficient
relative level of disturbance that can be transferred between two busbars or two parts of an electricity supply system for various operating conditions

NOTE: Identical to Clause 3.28 of PD IEC/TR 61000-3-7.

3.35
transmission system
part of a public electricity supply system that requires the owner or operator to hold a Transmission Licence in the United Kingdom

3.36
voltage change
single variation of the r.m.s. value or the peak value of the supply voltage unspecified with respect to form and duration

3.37
voltage dip
temporary reduction of the r.m.s. voltage at a point in the electricity supply system below a specified start threshold

NOTE: Identical to Clause 3.23 of BS EN 50160: 2010+A1: 2015.

3.38
voltage fluctuation
series of voltage changes that can be regular or irregular

NOTE: Types of voltage fluctuation include: repetitive voltage change associated with flicker, rapid voltage change, step voltage change, etc.

3.39
voltage swell
temporary increase of the r.m.s. voltage at a point in the electricity supply system above a specified start threshold

NOTE: Identical to Clause 3.23 of BS EN 50160: 2010+A1: 2015.

3.40
worst case normal operating condition
the condition that results in the maximum short-circuit impedance when measured at the PCC for the various normal operating conditions considered

4 Basic EMC concepts related to voltage fluctuations

4.1 General

Fluctuations in the supply system voltage can result in excessive flicker and can adversely affect the performance, or even damage, electrical equipment. This can result in complaints from customers to the system/network operator.

To minimise the risk of equipment damage and complaints it is necessary to ensure that:

a) customer installations and associated equipment have a level of immunity to voltage fluctuations; and

b) the magnitude and frequency of voltage fluctuations in the supply system do not exceed recommended compatibility and/or planning levels.

EMC is achieved when the supply system disturbance level/emission level is sufficiently low and the equipment immunity level is sufficiently high to prevent interference.

System operators/network operators are responsible for overall coordination of permitted voltage fluctuations to ensure EMC in the supply system. Consequently, this EREC recommends:

a) planning levels for assessing disturbances and emissions from customer disturbing equipment and fluctuating installations to be connected to public electricity supply systems;

b) emission limits for customers’ disturbing equipment and fluctuating installations that are or are proposed to be connected to public electricity supply systems.

Compatibility levels for LV public electricity supply systems in the UK are defined in BS EN 61000-2-2.

Equipment immunity levels are specified in relevant Standards[5] or agreed upon between equipment manufacturers and customers; as such no recommendations are made in this document.

4.2 Compatibility levels

Compatibility levels are the reference level in the supply system for setting of emission and immunity limits to ensure the EMC in the whole system (including system and connected equipment).

Compatibility levels are specified for entire supply systems so that there is only a small probability, typically 5%[6], that actual disturbance levels in the entire system will exceed the specified compatibility level. Similarly, there is only a small probability that actual equipment immunity levels will be below the compatibility level.

Compatibility levels for representative transmission systems and distribution networks in the UK are specified in Clause 5.

4.3 Planning levels

Planning levels are used for determining emission limits for individual fluctuating installations and take into consideration emissions from other fluctuating installations, i.e. flicker background levels.

Planning levels are specified at each system voltage level and allow coordination of voltage fluctuations between voltage levels[7].

Planning levels for different voltage levels in transmission systems and distribution networks in the UK are specified in Clause 5.

The nature of planning levels means that voltage fluctuations in parts of the electricity supply system could be higher than these levels.

4.4 Emission limits

Emission limits are maximum emission levels determined for either particular disturbing equipment or fluctuating installations that need to be met as a whole. Emission limits for disturbing equipment connected to LV public electricity supply systems are defined in the BS EN 61000 series of product standards. Emission limits that need to be met as a whole are determined from planning levels specified for the system concerned.

Emission levels are assessed against specified emission limits at a defined point (see 6.1.2). The intention is that under normal operating conditions emission levels do not exceed emission limits at any time.

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5 Immunity levels for products and equipment are specified in individual product standards or in BS EN 61000 Part 3 Standards insofar as they do not fall under the responsibility of product committees.

6 5% is a typical probability value, which may differ in real supply systems.

7 Different planning levels are necessary to take into account transfer of flicker from higher to lower voltage systems/networks.

Emission limits are specified in accordance with the approach in Clause 6 for assessing the connection of disturbing equipment and fluctuating installations to transmission systems and distribution networks.

4.5 Illustration of EMC concepts

Figure 1 and Figure 2[8] illustrate the concept of compatibility levels, planning levels and emission limits and how EMC, relating to voltage fluctuations in the supply system, is achieved.

Figure 1 shows how EMC is achieved on a supply system wide basis.

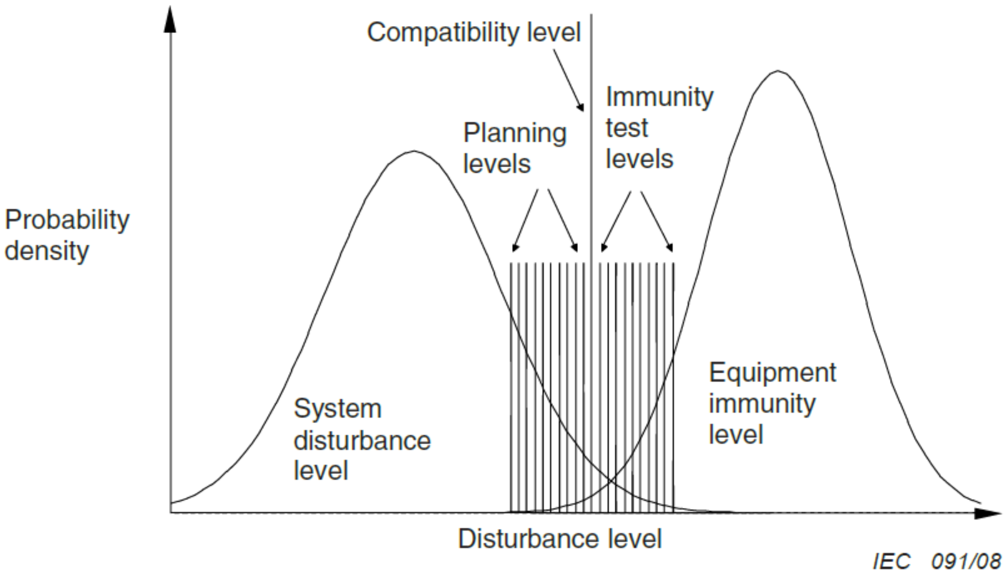

Figure 1 — Illustration of EMC concepts relevant to system

Figure 1 shows that there is a chance that interference might occur at certain times or certain locations in the system. This is recognition that the system operator/network operator cannot control all points of the system at all times.

[8] Figure 1 and Figure 2 are reproduced from PD IEC/TR 61000-3-7.

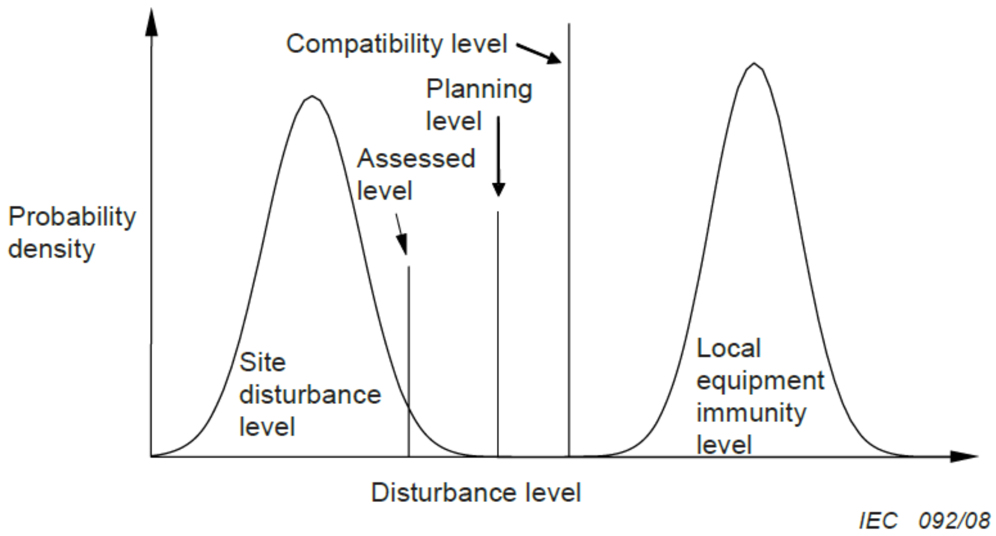

Figure 2 — Illustration of EMC concepts relevant to local site

Figure 2 shows conceptually that, on a local site basis, specifying suitable planning levels should ensure there is no overlap of disturbance and immunity levels.

4.6 Flicker

Flicker is the result of repetitive voltage fluctuations, caused by disturbing equipment, in the supply system, which can be observed by changes in luminance of incandescent lamps.

The severity of flicker is dependent upon the magnitude and the frequency of the voltage fluctuations. High powered process type equipment which does not have a steady power demand and can draw frequently changing current is typically associated with flicker related voltage fluctuations.

The severity of flicker is quantified using flicker severity levels, P_{st} and P_{lt}, where P_{st} is the short-term flicker severity measured over a 10-minute interval and P_{lt} is long-term flicker severity measured over a 2-hour interval, typically. Values of P_{st} and P_{lt} are determined from voltage fluctuation data using a flickermeter algorithm which conforms to the requirements of BS EN 61000-4-15 (see 6.3.1).

4.7 Rapid Voltage Change (RVC)

RVC is a fast change in the r.m.s.[9] voltage between two steady state voltage conditions.

RVCs are generally caused by equipment start-up and shutdown including:

- motor starting/stopping;

[9] RMS is measured over one cycle refreshed every half-cycle in accordance with the method in BS EN 61000-4-30.

- energising transformers;
- switching capacitors/inductors, e.g. capacitor banks and reactors;
- switching in/out of large electrical loads;
- tap-changer operation;
- tripping of load/generation.

RVCs generally relate to infrequent or very infrequent events that can occur randomly on the system/network or events that need to be separated by time periods, which exceed the minimum intervals stated in this EREC.

The characteristics of a voltage dip and a voltage swell are shown in Figure 3 and Figure 4 respectively.

Limits for RVCs are shown in Table 4.

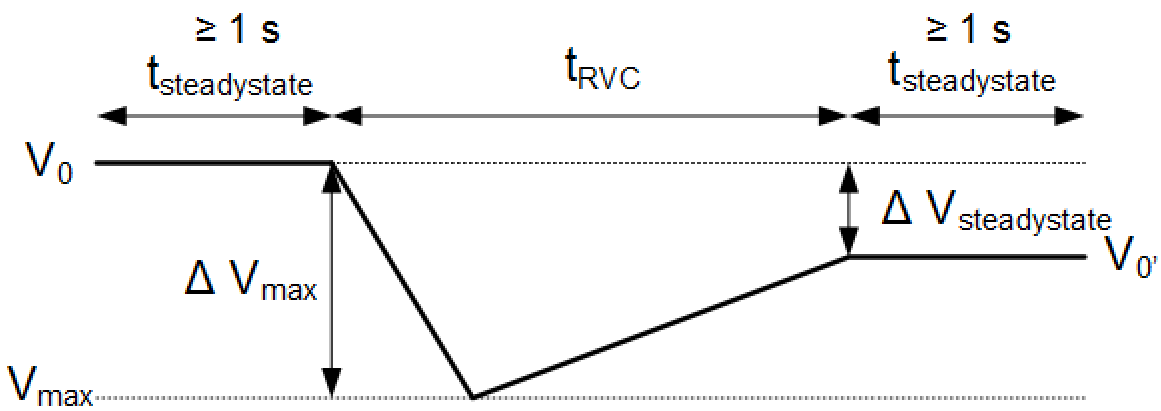

Figure 3 — Illustration of RVC characteristic for voltage dip

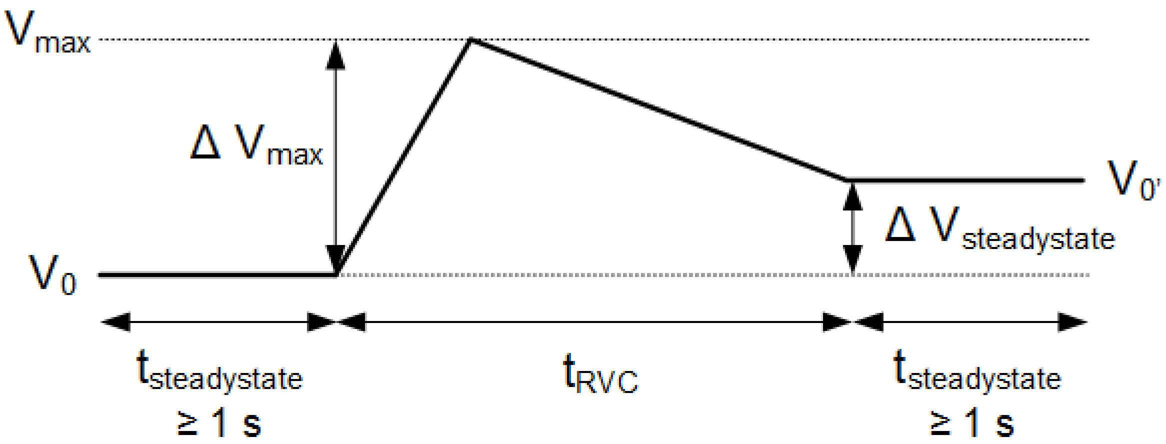

Figure 4 — Illustration of RVC characteristic for voltage swell

Where:

t_{RVC}	is the time duration of the RVC between steady state conditions
V_{max}	is the maximum voltage magnitude between two steady state voltage conditions
V_0	is the initial steady state voltage prior to the RVC
$V_{0'}$	is the final steady state voltage after the RVC
$V_{steadystate}$	is the voltage at the end of a period of 1 s during which the rate of change of system voltage over time is ≤ 0.5%.
ΔV_{max}	is the absolute value of the maximum change in the system voltage (V_{max}) relative to V_0
$\Delta V_{steadystate}$	is the difference in voltage between the initial steady state voltage prior to the RVC (V_0) and the final steady state voltage after the RVC ($V_{0'}$)
$\%\Delta V_{max}$	$= 100\times\frac{\Delta V_{max}}{V_n}$
$\%\Delta V_{steadystate}$	$= 100\times\frac{\Delta V_{steadystate}}{V_n}$
V_n	is the nominal system voltage

All voltages are the r.m.s. voltage measured over one cycle refreshed every half cycle in accordance with BS EN 61000-4-30.

For RVCs, $\Delta V_{steadystate}$ equates to the value of step voltage change.

5 Compatibility levels, planning level and emission limits

5.1 General

Separate compatibility levels, planning levels and emission limits apply to different types of voltage fluctuations, i.e. flicker and RVC. Levels/limits for flicker and RVC are stated in Clause 5.2 and 5.3 respectively. Limits for step voltage change are stated in Clause 5.4.

5.2 Flicker

5.2.1 Compatibility levels

The following compatibility levels for flicker in Table 1 are specified for LV supply systems[10].

Table 1 — Compatibility levels for flicker in LV supply systems

Compatibility level	
P_{st}	P_{lt}
1.0	0.8

Compatibility levels are such that there is a 5% probability that measured disturbance in the wider area system could exceed the specified levels based on a statistical distribution of measurements varying in both time and location [on the supply system].

The magnitude of any frequently occurring voltage change should not exceed the limits of the voltage characteristic shown in Figure 5, other than for RVCs (see 4.6)[11].

Compatibility levels should only be used for evaluating system-wide disturbance by system/network operators; planning levels should be used for evaluating the acceptability of disturbance levels at a local site or specific location.

5.2.2 Planning levels

Planning levels for distribution networks and transmission systems in the United Kingdom are dependent upon the nominal voltage of the system.

Planning levels for flicker are specified in Table 2.

Planning levels specified in Table 2 should be used to derive flicker limits for disturbing equipment and fluctuating installations according to the staged approach outlined in Clause 6.3. In principle, disturbing equipment and fluctuating installations that do not meet the criteria for unconditional connection under Stage 1 are required to meet the flicker limit allocated under the Stage 2 assessment. Under special circumstances, remaining headroom may be allocated to the customer, on a ‘first come first served’ basis, under the Stage 3 assessment process for flicker (see 6.3.1).

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[10] Compatibility levels for supply systems with nominal voltages greater than LV are not currently specified.

[11] When measured at the PCC (see 6.1.2).

The planning levels in Table 2 are absolute values and should not be exceeded given the real risk of customer complaints occurring.

The planning levels in Table 2 allow for coordination of voltage fluctuations based on typical transfer coefficients for flicker that have been determined for transmission systems and distribution networks in the United Kingdom such that the likelihood of visual nuisance to LV customers is minimised. In some non-typical parts of a network[12], specific consideration may be required to ensure that flicker at higher voltage levels are co-ordinated to prevent interference.

Table 2 — Planning levels for flicker

Supply system Nominal voltage	Planning level	
	P_{st}	P_{lt}
LV	1.0	0.8
3.3 kV, 6.6 kV, 11 kV, 20 kV, 33 kV	0.9	0.7
66 kV, 110 kV, 132 kV, 150 kV, 200 kV, 220 kV, 275 kV, 400 kV	0.8	0.6
NOTE 1: Planning levels for LV connections are equal to compatibility levels. NOTE 2: The magnitude of P_{st} is linear with respect to the magnitude of the voltage changes giving rise to it. NOTE 3: Extreme caution is advised in allowing any excursions of P_{st} and P_{lt} above the planning level.		

Table 3 — Typical transfer coefficients

System voltage level	T_{Pst} T_{Plt} [1]
400/275 kV to 132/110 kV	0.85
400/275 kV to 66 kV	0.85
400/275 kV to 33/22 kV	0.80
400/275 kV to 20/11/6.6 kV	0.70
132/110 kV to 66 kV	0.95
132/110 kV to 33/22 kV	0.90
132/110 kV to 20/11/6.6 kV	0.75
66 kV to 33/22 kV	0.95
66 kV to 20/11/6.6 kV	0.90
33/22 kV to 20/11/6/6 kV	0.90
11 kV to LV	1.0

[12] For example: Where there are higher than standard impedances between voltage levels, or particularly weak supply systems/networks with long feeders and limited current capacities, which could have higher transfer coefficients.

NOTE 1: Transfer coefficients are typical of those measured in UK transmission systems / distribution networks. NOTE 2: The transfer coefficients are based on the results of data and modelling by National Grid for the GB supply system. NOTE 3: Transfer coefficients equally apply to assessment of RVC as well as flicker.
[1] The transfer coefficients apply to both P_{st} and P_{lt}.

The typical transfer coefficients in Table 3 should be used unless specific flicker propagation data exists (see 7.2.2).

In the absence of specific flicker propagation data or where flicker at the PCC needs to be specifically assessed, it should be assumed that flicker is not transferred from lower voltage systems to higher voltage systems due to the associated increase in short-circuit power.

5.2.3 Emission limits

Emission limits from a fluctuating installation should be such so as to ensure planning levels at the PCC (see 6.1.2) are not exceeded taking into account flicker background levels.

5.3 Rapid voltage changes

5.3.1 Compatibility levels

Compatibility levels for RVC are common across transmission systems and distribution networks in the United Kingdom irrespective of the nominal voltage of the system.

Compatibility levels for RVC are the same as the planning levels specified in Table 4[13].

RVCs emanating from fluctuating installations that are thought likely to be coincident should be specifically assessed to ensure that the combined effect will not result in RVCs exceeding the compatibility level.

5.3.2 Planning levels

Planning levels for RVC are specified in Table 4.

The planning levels in Table 4 define absolute limits of maximum voltage change (ΔV_{max}) and steady state voltage change ($\Delta V_{steadystate}$) for RVCs according to the maximum number of occurrences expected within a specified time period.

These planning levels take into account the need to minimise disturbance to other customers connected to the system, associated with RVCs, whilst recognising that the visual disturbance caused by RVCs is not as severe or frequent as for flicker. The planning levels in Table 4 have been determined so as to avoid maloperation of electrical equipment connected to the system at the maximum voltage change permitted for RVCs.

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[13] The assumption being that, in practice, there is no coincidence between RVCs in transmission systems or distribution networks.

Table 4 — Planning levels for RVC

Category	Title	Maximum number of occurrence	Limits $\%\Delta V_{max}$ & $\%\Delta V_{steadystate}$	Example Applicability
1	Frequent events	(see NOTE 1)	As per Figure 5	Any single or repetitive RVC that falls inside Figure 5
2	Infrequent events	4 events in 1 calendar month (see NOTE 2)	As per Figure 6 $\lvert \%\Delta V_{steadystate} \rvert \leq 3\%$ For decrease in voltage: $\lvert \%\Delta V_{max} \rvert \leq 10\%$ (see NOTE 3) For increase in voltage: $\lvert \%\Delta V_{max} \rvert \leq 6\%$ (see NOTE 4)	Infrequent motor starting, transformer energisation, G59 [4] re-energisation (see NOTE 7)
3	Very infrequent events	1 event in 3 calendar months (see NOTE 2)	As per Figure 7 $\lvert \%\Delta V_{steadystate} \rvert \leq 3\%$ For decrease in voltage: $\lvert \%\Delta V_{max} \rvert \leq 12\%$ (see NOTE 5) For increase in voltage: $\lvert \%\Delta V_{max} \rvert \leq 6\%$ (see NOTE 6)	Commissioning, maintenance & post fault switching (see NOTE 7)

NOTE 1: ±6% is permissible for 100 ms reduced to ±3% thereafter as per Figure 5.
If the profile of repetitive voltage change(s) falls within the envelope given in Figure 5, the assessment of such voltage change(s) shall be undertaken according to the recommendations for assessment of flicker <u>and</u> shall conform to the planning levels provided for flicker.
If any part of the voltage change(s) falls outside the envelope given in Figure 5, the assessment of such voltage changes, repetitive or not, shall be done according to the guidance and limits for RVCs.

NOTE 2: No more than 1 event is permitted per day, consisting of up to 4 RVCs, each separated by at least 10 minutes with all switching completed within a two-hour window.

NOTE 3: −10% is permissible for 100 ms reduced to -6% until 2 s then reduced to -3% thereafter as per Figure 6.

NOTE 4: +6% is permissible for 0.8 s from the instant the event begins then reduced to +3% thereafter as per Figure 6.

NOTE 5: −12% is permissible for 100 ms reduced to −10% until 2 s then reduced to -3% thereafter as per Figure 7.

NOTE 6: +6% is permissible for 0.8 s from the instant the event begins then reduced to +3% thereafter as per Figure 7.

NOTE 7: These are examples only. Customers may opt to conform to the limits of another category providing the frequency of occurrence is not expected to exceed the 'Maximum frequency of occurrence' for the chosen category. Where the measured emission level exceeds the expected emission level, paragraph 4 of Clause 6.1.4 applies.

Where:

a) $\%\Delta V_{steadystate} = 100 \times \frac{\Delta V_{steadystate}}{V_n}$ and
$\%\Delta V_{max} = 100 \times \frac{\Delta V_{max}}{V_n}$

b) V_n is the nominal system voltage.

c) $V_{steadystate}$ is the voltage at the end of a period of 1 s during which the rate of change of system voltage over time is ≤ 0.5%.

d) $\Delta V_{steadystate}$ is the difference in voltage between the initial steady state voltage prior to the RVC (V_0) and the final steady state voltage after the RVC ($V_{0'}$).

e) ΔV_{max} is the absolute change in the system voltage relative to the initial steady state system voltage (V_0).

f) All voltages are the r.m.s. of the voltage measured over one cycle refreshed every half a cycle as per BS EN 61000-4-30.

g) The applications in the 'Example Applicability' column are examples only and are not definitive.

The limits for RVCs in Category 2 and Category 3 of Table 4 take into account differences in the perceptibility of RVC compared with flicker associated with continuously fluctuating loads. As such, conformance to flicker limits in Clause 5.1, although desirable, is not a requirement for RVCs in Category 2 and Category 3.

The voltage change limit is the absolute maximum allowed of either the phase-to-earth voltage change or the phase-to-phase voltage change, whichever is the highest. The limits do not apply to single phasor equivalent voltages, e.g. positive phase sequence (PPS) voltages. For high impedance earthed systems, the maximum phase-to-phase, i.e. line voltage, should be used for assessment.

Voltage changes in Category 1 should not only fall within the envelope in Figure 5 but should also meet the flicker limits as determined from assessment of flicker (see 6.3).

RVCs in Category 2 and 3 should not exceed the limits depicted in the time dependant characteristic shown in Figure 6 and Figure 7 respectively.

Any RVCs permitted in Category 2 and Category 3 should be at least 10 minutes apart.

The value of $V_{steadystate}$ should be established immediately prior to the start of a RVC. Following a RVC, the voltage should remain within the relevant envelope, as shown in Figures 5, Figure 6 or Figure 7, until a $V_{steadystate}$ condition has been satisfied.

The voltage change between two steady state voltage conditions should not exceed 3%[14].

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[14] The limit is based on 3% of the nominal voltage of the system (V_n) as measured at the PCC. The step voltage change as measured at the customer's supply terminals or equipment terminals could be greater. For

The limits apply to voltage changes measured at the PCC (see 6.1.2).

At transmission system voltage levels, Category 3 events that are planned should be notified to the relevant Transmission System Operator in advance. At distribution network voltage levels, the requirement to notify planned Category 3 events is at the discretion of the relevant Distribution Network Operator.

Category 2 events do not need to be notified to the system/network operator.

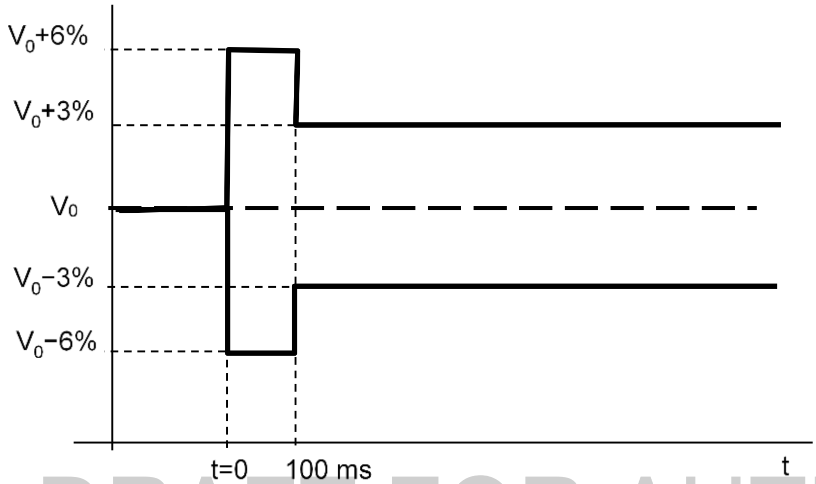
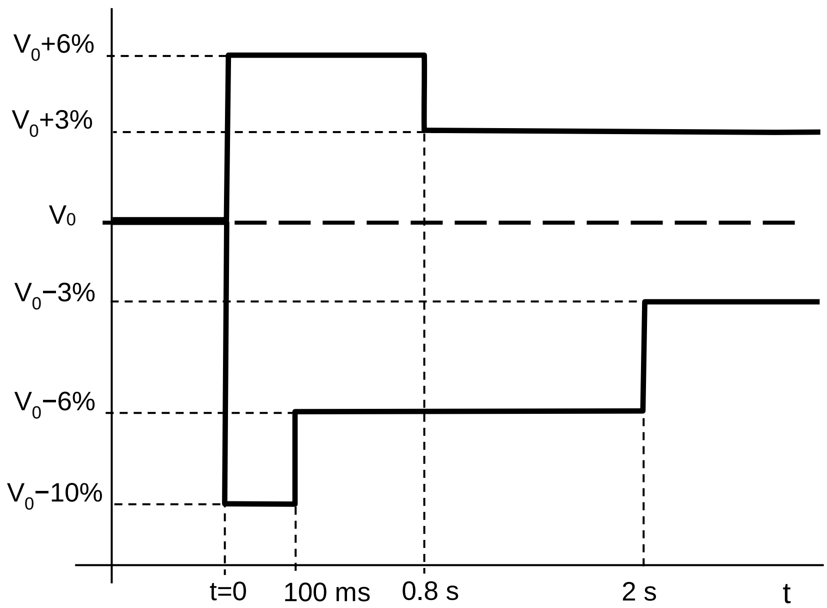


Figure 5 — Voltage characteristic for frequent events



example: The step voltage change limit stated in BS EN 61000-3-3 and BS EN 61000-3-11 is 3.3% when measured at the equipment terminals.

Figure 6 — Voltage characteristic for infrequent events

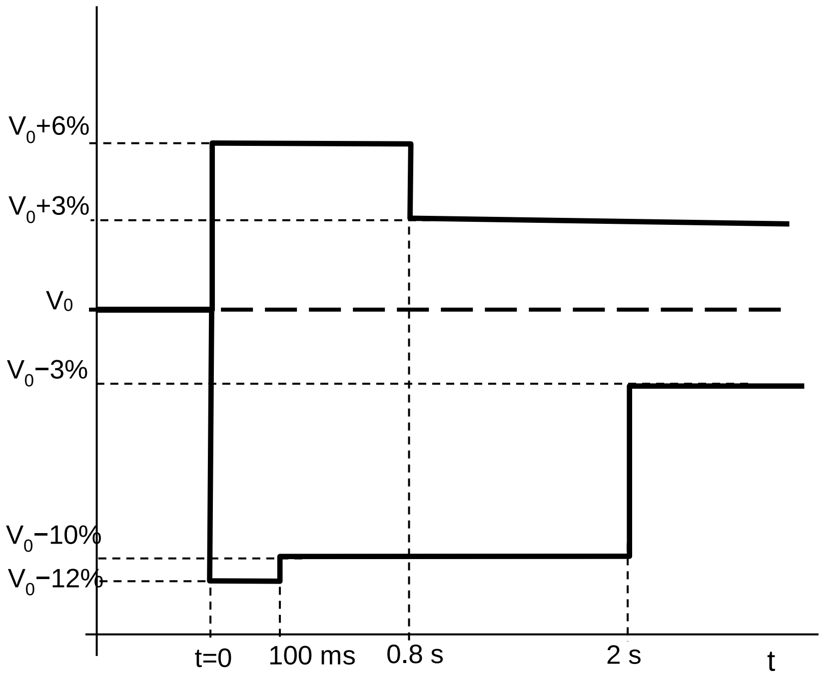


Figure 7 — Voltage characteristic for very infrequent events[15]

5.3.3 Emission limits

RVCs from individual fluctuating installations should not exceed the relevant planning level(s) in Table 4.

Limits for individual fluctuating installations may need to be lower than those in Table 4 where there is likely to be co-incident RVCs from different installations, such that the combined effect of co-incident RVCs from fluctuating installations are within the limits set out in Table 4. Measures should be taken to prevent co-incident RVCs at the PCC, where reasonably practicable. This requires knowledge to be obtained about the potential for RVCs from existing fluctuating installations to coincide with those for proposed connections.

The requirement to prevent co-incident RVCs exceeding the limits in Table 4 at the PCC does not apply to: a) fault clearance operations; or b) immediate operations in response to fault conditions.

[15] In Northern Ireland, lesser limits than those in Figure 7 apply for as long as Engineering Recommendation G59/1/NI is applied.

5.4 Step voltage change limit

A 3% general limit applies to the magnitude of percentage step voltage changes regardless of frequency of occurrence.

NOTE: For the purposes of this EREC, percentage step voltage change is the value of step voltage change in volts expressed as percentage change of the nominal system voltage (V_n).

6 Assessment of disturbing equipment and fluctuating installations

6.1 General guidelines for assessment

6.1.1 Assessment procedure

Assessment of step voltage change should follow the procedure in Clause 6.2.

Assessment of flicker should follow the procedure in Clause 6.3.

Assessment of RVCs should follow the procedure in Clause 6.4.

The flowchart in Figure 8 summarises the high-level assessment procedure to be followed.

Disturbing equipment and fluctuating installations that can be characterised as producing RVCs but could also result in flicker should be assessed for RVC (see 6.4) and flicker (see 6.3).

NOTE: The relevant clauses in this EREC are identified in parentheses.

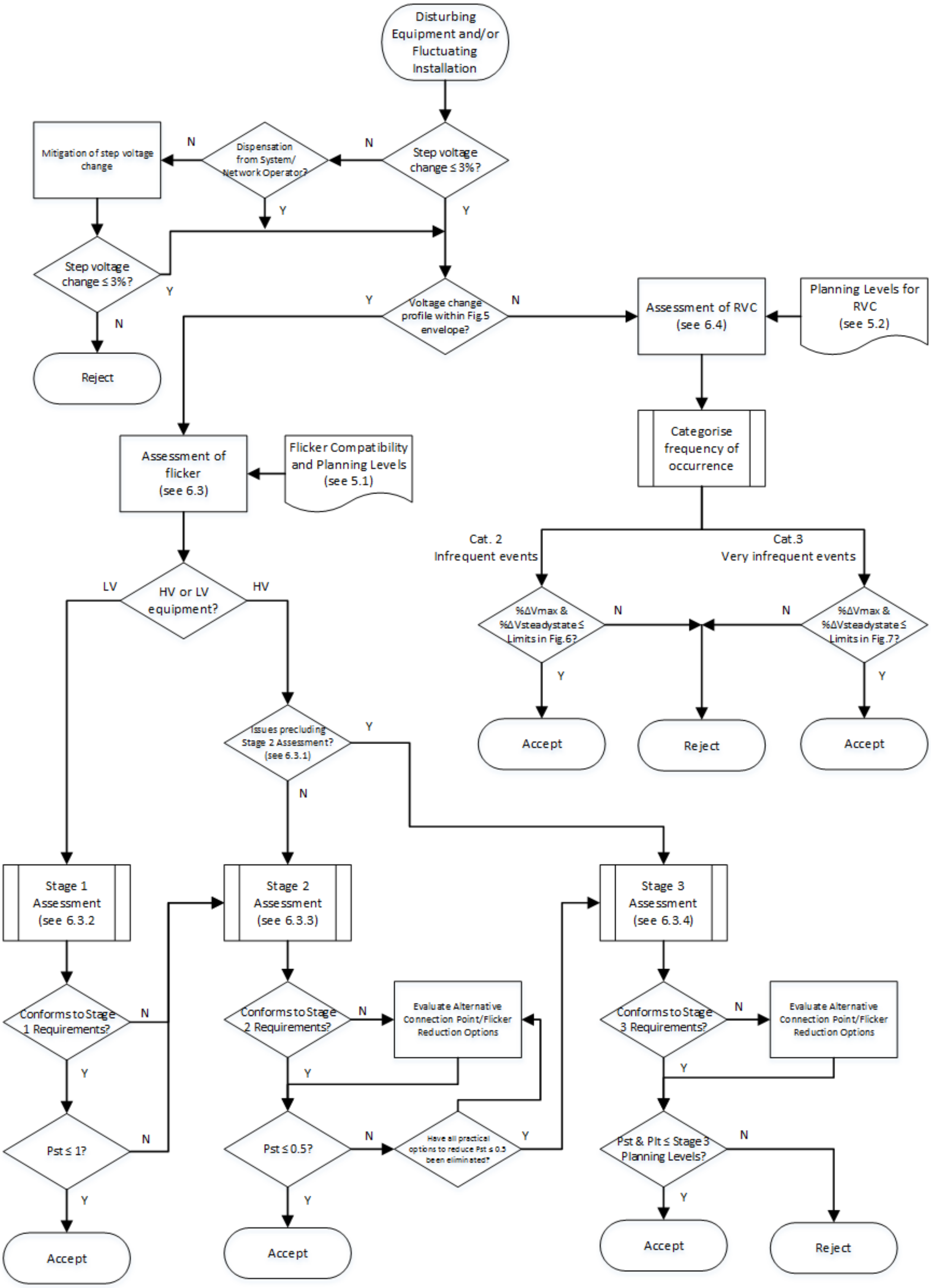


Figure 8 — Flowchart assessment procedure

6.1.2 Point of evaluation

The assessment of voltage fluctuation should be at the PCC unless otherwise specified by the system/network operator when evaluation at the PCC is not appropriate (see 6.3.4).

6.1.3 Capability of equipment to function correctly

Assessment in accordance with this EREC considers the effect of voltage fluctuations from disturbing equipment/fluctuating installations on the capability of other equipment connected to the public electricity supply system to function correctly.

6.1.4 Information requirements and responsibilities

The information to be provided and the responsibilities of the customer and system/network operator in the assessment process should be as those in Table 5.

The system/network operator shall declare maximum values of supply system impedance for networks with a nominal voltage greater than LV in accordance with the provisions of Clause 6.1.5 and Clause 6.1.6.

Details of disturbing equipment should be: provided in a timely manner; sufficiently detailed; and in a format that enables the system/network operator to accurately model it.

Where measured emission levels are found to exceed predicted emission levels in the compliance report and this has a material effect, the system/network operator may:

a) require the customer to take mitigating action, where such action is reasonable;

b) require the customer to disconnect the disturbing equipment until mitigating action can be taken;

c) consider the need to disconnect the fluctuating installation.

Where reasonably practicable, direct measurement of flicker severity should be carried out following connection of the disturbing equipment/fluctuating installation to validate the results of calculation and modelling.

Table 5 — Information requirements and responsibilities *(1 of 2)*

Information	Requirement	Assessment Stage	Responsibility
Supply system impedance - LV only	For single-phase: Measurement of supply phase to neutral loop impedance at the customer supply terminals (see NOTE 1) or Calculation of supply phase to neutral loop impedance at the customer supply terminals for normal supply arrangement (see NOTE 2) For three-phase: Measurement of supply phase to phase supply impedance at the customer supply terminals (see NOTE 1) or Calculation of supply phase to phase impedance at the customer supply terminals for normal supply arrangement (see NOTE 2)	Stage 1	Customer Network Operator (on request) Customer Network Operator (on request)
Service current capacity	Check against Connection Agreement Check service records and/or inspection of cut-out (see NOTE 3)	Stage 1	Customer Network Operator (on request)
Disturbing equipment details:	Type of equipment Rated voltage, current, power Single-phase or three-phase connection Single-phase or three-phase impedance Starting/stopping current characteristics Operating cycle (periods of operation) Statement of EMC compliance with relevant product standards, e.g. BS EN 61000-3-3 (see NOTE 4)	Stage 1,2 & 3	Customer

Table 5 — Information requirements and responsibilities *(2 of 2)*

Information	**Requirement**	**Assessment Stage**	**Responsibility**
P28 compliance assessment	Assess flicker/RVC emission against compatibility/planning levels in P28 Issue 2. Provide compliance report for Network Operator Assess compliance report from customer for acceptability	Stage 2 & 3	Customer (see NOTE 5) System/Network Operator
Emission measurements and validation	Measurement of customer's emission levels and validation against predicted levels in P28 compliance report	Stage 2 & 3	Customer & System/Network Operator (see NOTE 6)
Supply system impedance - except LV (see 6.1.5)	Declaration of maximum supply system impedance at the PCC	Stage 1, 2 & 3	System/Network Operator
Known future connections/ alterations (see 6.1.6)	Provide system/network information in Long Term Development Statements, where available, and similar documents Consider known future alterations to the supply system in supply system impedance information (see NOTE 7) Consider known future connection/alterations (supply system and disturbing equipment/fluctuating installation) in emissions assessment	Stage 1, 2 & 3	System/Network Operator System/Network Operator Customer
Flicker background level (see 7)	Measurement of existing flicker background level (pre-connection)	Stage 3	System/Network Operator

NOTE 1: This check is required to be carried out by a competent person/organisation to ensure the supply impedance is equal to or less than the manufacturer declared maximum supply impedance for the equipment to be installed. For further information see BS EN 61000-3-3 and BS EN 61000-3-11.

NOTE 2: The source impedance upstream of the distribution transformer can be excluded where it is insignificant compared to the impedance of the distribution transformer.

NOTE 3: There is a requirement under BS 7671 (IET Wiring Regulations), to assess supply adequacy. It is important to note that the current rating of the cut-out fuse holder by itself is not indicative of the service current capacity.

NOTE 4: The System/Network Operator may provide assumed data, where data is not provided by the customer and will advise the customer accordingly. The costs could be chargeable to the customer according to the Network Operator's charging statements and methodologies.

NOTE 5: The System/Network Operator may elect to carry out the assessment on behalf of the customer. In this case a summary of the assessment and any relevant data should be provided to the customer on request and subject to meeting any confidentiality requirements.

NOTE 6: Depending upon the extent of studies carried out and the results provided, the system/network operator may decide not to measure customer emission levels for Stage 2 assessments. Notwithstanding, it is incumbent on the customer to ensure that actual emission levels post connection conform to emission limits.

NOTE 7: The onus is on the system/network operator to determine what system developments are known and reasonably foreseeable and to advise these for the assessment of disturbing equipment/fluctuating installations.

6.1.5 Supply system impedance

Where knowledge of supply system impedance is required for calculating the magnitude of voltage fluctuations, then credible maximum values should be used. These values should generally coincide with the worst case normal operating conditions (see 6.1.6). Where operation of disturbing equipment/fluctuating installations is seasonal then supply system impedances at coincident time(s) of year may be used.

When assessing the voltage fluctuation, which would be imposed on the supply to other customers, then only the supply system impedance up to the PCC should be taken into account. The effect on supply system impedance from customer owned local generation that can be relied upon to be in operation may be considered.

Information provided by the system/network operator regarding planned alterations to the public electricity supply system, which would increase or decrease the supply system impedance, should be taken into account[16].

Any local conditions that could increase the supply system impedance at the PCC should be considered (see 6.1.6).

The effects of embedded generation on the supply system impedance should be ignored unless there is a long-term guarantee that this generation would be operating at the same time as the disturbing equipment and/or fluctuating installation. In this case, planned outages of such embedded generation should be considered.

In the absence of seasonal data, the supply system impedance in summer, with minimum generating plant[17] in operation and credible planned outages, should be used.

At LV, the source impedance upstream of HV/LV distribution transformers may be ignored where it is insignificant compared with the impedance of the distribution transformer. The source impedance upstream of 11 000/230 V pole mounted transformers with small rated powers should not be ignored.

For assessing voltage fluctuation caused by three-phase connected equipment, the initial symmetrical short-circuit impedance of the supply system, $Z_k^{"}$ ($R_k^{"}$ and $X_k^{"}$), should be used.

NOTE: The short-circuit impedance $Z_k^{"}$ corresponds to the initial symmetrical short-circuit current, $I_k^{"}$.

Where the initial symmetrical short-circuit impedance of the supply system, $Z_k^{"}$ is not available then the symmetrical short-circuit breaking current I_b may be used to calculate the short-circuit impedance of the supply system.

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16 Planned system alterations and associated changes to fault levels can be obtained from Long Term Development Statements, where available, and similar documents prepared by system/network operators, noting that the fault levels in Long Term Development Statements are maximum fault levels.

17 'Minimum generation plant' equates to the expected minimum aggregated power output of generation connected to the system in any year, which is consistent with the lowest contribution from generation to system fault levels.

As the symmetrical short-circuit breaking current I_b is normally smaller than the initial symmetrical short-circuit current $I_k^{"}$, using I_b instead of $I_k^{"}$ for assessing voltage fluctuation would normally produce a more pessimistic result[18].

For assessing voltage fluctuation caused by single-phase connected equipment, the short-circuit loop impedance between the source and load should be used, whether that is between the phase and neutral or between two phases of the supply system.

For assessing RVC the appropriate subtransient reactance of the disturbing equipment should be used, where this information is available.

6.1.6 Normal operating conditions

Voltage fluctuations should be assessed under the worst case normal operating condition(s) unless specified otherwise by the system/network operator.

Normal operating conditions for the supply system include those operating conditions in Table 6, where the system/network is designed to remain within acceptable/statutory limits.

Voltage fluctuations during credible outage conditions should be considered, including planned and/or fault outages consistent with those where there is a requirement to secure demand as required by security of supply standards, i.e. ENA Engineering Recommendation P2 for HV distribution networks[19] and National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) for transmission systems[20]. For generation, the most onerous condition(s) the generator(s) will be expected to normally operate should be considered.

For an arrangement where there are two transformers in a system/network operator's substation that are normally operated in parallel, a planned outage of one transformer would generally result in the worst case normal operating condition.

Considerations of outages in the electricity supply system may be disregarded for assessment of LV disturbing equipment/fluctuating installations.

Voltage fluctuations are not expected to conform to planning levels under the following conditions.

a) Temporary/abnormal conditions or whilst steps are taken to maintain/restore supplies to customers, where otherwise supplies would be interrupted[21].

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[18] Further information on short-circuit currents can be found in BS EN 60909-0.

[19] For HV distribution networks, a first circuit outage condition generally only needs to be considered, where a 'first circuit outage' condition refers to a single outage (planned or fault) of a circuit or item of plant.

[20] For transmission systems, a second circuit outage condition generally needs to be considered, where a 'second circuit outage' condition refers to a first circuit outage (planned or fault) with the additional consideration of a fault outage on a second circuit or item of plant within the same load group as the first.

[21] For example: Most 6.6 kV, 11 kV, 20 kV and 33 kV networks are not designed to operate within acceptable limits for a second circuit outage condition.

b) Emergency conditions.

Particular care should be taken when considering the effect of local system outages given the following.

a) An outage of a local circuit might not give rise to the worst case normal operating condition.

b) An outage of a local circuit needs to be considered together with wider system outage scenarios so minimum acceptable security of supply standards are still met.

Table 6 — System/network conditions - Normal operating conditions

System/network operating condition	Description
Normal network configuration	Normal running arrangement with normal open point(s). No network assets out-of-service for construction, maintenance or faults
Alternative network configuration(s)	Alternative running arrangement(s) with substitute open point(s). No network assets out-of-service for construction, maintenance or repair
Planned outages (see NOTE)	Planned outages of specific network assets for construction, maintenance or repair activities
Fault outages (see NOTE)	Running arrangement taking into account credible fault outage scenario(s) for normal/alternative network configuration(s). Compliant with network design limits before fault outage and within a short time after fault outage, where reconfiguration of network is required
Switching operations (including reactive compensation)	Energisation and de-energisation of network assets. Reactive compensation. Reconfiguration of network
Protection operation (including G59 [4] protection operation)	Operation of protection and disconnection of load/generation for which the network is designed to cater for
Demand / generation variations	Variations in demand/generation within rating of network under normal and alternative network configurations
Local embedded/distributed generation	Generally, can be ignored unless there is a long-term guarantee that this generation would be operating at the same time as the disturbing equipment and/or fluctuating installation (see 6.1.5)
NOTE: For various credible planned/fault outage scenarios the scenario that results in the maximum supply system impedance should be generally chosen.	

Where operation of the disturbing equipment/fluctuating installation can be assured so as not to coincide with a particular network operating condition then assessment of that particular network operating condition can be discounted.

6.1.7 Exceeding planning levels

Where emission levels are assessed to exceed the planning levels in this EREC, options for reducing emission levels to acceptable levels should be evaluated. These include but are not limited to:

a) a change in the supply system arrangement including new proposed connection point that would reduce the maximum supply system impedance and/or reduce the disturbance at the PCC;

b) modification to the disturbing equipment or fluctuating installation to reduce voltage fluctuations including use of compensation equipment/techniques[22].

Any cost of taking remedial action to conform to planning levels should be borne by the customer.

Further information on mitigation actions can be found in Part 5 of the BS EN 61000 series of EMC Standards.

Emission levels higher than specified emission limits may be permitted by system/network operators under certain circumstances. Guidance can be found in ENA Engineering Report P28 [8].

6.2 Assessment of step voltage change

Conformance to the 3% step voltage change limit should be assessed as a first step.

In certain cases, where special circumstances apply, the system/network operator may, at its discretion, allow larger step voltage changes to occur, e.g. continuous process plant where larger motors are only started once in several months. The system/network operator may also give special limited approval for the use of some types of equipment that result in step voltage changes in excess of 3% without the need for individual consideration.

6.3 Assessment of flicker

6.3.1 General

Assessment of flicker severity is based on the long established and reliable measures P_{st} and P_{lt}. These measures should be used for assessing disturbance to all other equipment connected not just lighting.

Flicker severity shall be characterised according to a flickermeter conforming to the requirements of BS EN 61000-4-15.

The 95th percentile value of P_{st} and P_{lt} measured over 1 week should be used to assess flicker against flicker planning levels in Table 2. Where measurements are made over several weeks then the value of flicker severity for each weekly measurement period should not exceed the applicable planning limits.

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22 For example: point-on-wave switching for energising transformers.

NOTE: Where flicker severity is measured over a number of weekly measurement periods, the values in each week of measurement need to conform to the applicable planning limit, not the flicker severity over the whole measurement period.

It is generally acceptable for customers to connect disturbing equipment to LV public electricity supply systems without any reference to the network operator or specific assessment of flicker providing:

a) the disturbing equipment is declared as conforming to that part of BS EN 61000 appropriate to the product; and

b) the LV supply system source impedance at the customer supply terminals is equal to or less than:

   i. the reference impedance (Z_{test})[23] stated in that part of BS EN 61000 appropriate to the product; or

   ii. the maximum value of the supply impedance at which equipment would meet required limits (Z_{max}), as declared by the equipment manufacturer.

The LV public electricity supply system impedance can be determined by one or more of the following approaches.

a) Use of generic supply system impedance values for metered connections (see Table 7).

b) Measurements of supply system impedance.

c) Specific supply system impedance values provided by the network operator.

The following supply system impedances, based on generic values of supply impedance for LV public electricity supply systems in the United Kingdom, may be used for approximate calculations in the absence of measurements or specific LV supply system impedance data.

Table 7 — Generic supply impedance for LV metered connections

Supply	**Service capacity (per phase)**	**Supply impedance (single-phase connections)**	**Supply impedance (three-phase connections)**
230 V single-phase PME supply	< 100 A	0.34 Ω	-
230 V single-phase non PME supply	<100 A	0.47 Ω[A]	-
400 V three-phase supply	150 A	0.42 Ω	0.25 Ω
400 V three-phase supply	200 A	0.31 Ω	0.19 Ω
400 V three-phase supply	300 A	0.21 Ω	0.13 Ω
400 V three-phase supply	400 A	0.16 Ω	0.10 Ω
400 V three-phase supply	600 A	0.10 Ω	0.06 Ω

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23 Z_{ref} represents a maximum value of source impedance, which is used for testing the appliance or disturbing equipment.

NOTES: 1 The values of supply impedance are derived from values in Table 1, Table 5 and Table 6 of PD IEC/TR 60725, which have been deemed most appropriate to the United Kingdom. 2. For three-phase supplies the supply impedance to be used will depend upon whether disturbing equipment is connected single-phase or three-phase.
[A] Derived from survey data for the UK published in PD IEC/TR 60725, where 98% of 230 V single-phase supplies with <100 A capacity had a supply system impedance, measured at the supply terminals, less than or equal to 0.4 + j0.25 Ω.

NOTE: Actual LV supply system impedances might be higher than the typical values stated. For example, where supplied from pole mounted transformers with low rated power and LV mains cables or service cables with small cross-sectional area.

For LV supplies with a declared supply capacity ≥ 100 A then specific data provided by the network operator should be used for assessment of flicker.

Where individual items of disturbing equipment within a fluctuating installation work together as a system,[24] flicker from the system, as well as those from the individual items of disturbing equipment, should be assessed against the relevant requirements in this EREC.

Assessments should follow a three-stage procedure summarised in Figure 9.

Stage 1 (see 6.3.2) is a simplified assessment for assessing discrete items of LV equipment based on equipment standards; it is not applicable to HV connections or to the assessment of disturbing equipment that work together as a system, which should be assessed under Stage 2. LV disturbing equipment and/or fluctuating installations that meet the Stage 1 assessment criteria can be connected without specific assessment or reference to the network operator. The assessment criteria are such that individual LV equipment conforming to relevant BS EN 61000 product standards or the connection of multiple items of similar LV equipment with limited fluctuating power can be connected under Stage 1 with no prospect of interference.

Stage 2 (see 6.3.3) is an assessment of flicker levels from disturbing equipment and/or fluctuating installations against a specified planning level. The assessment does not require the existing flicker background level to be taken into account. Disturbing equipment and/or fluctuating installations can be connected under Stage 2 without reference to the network operator or further assessment providing emission levels do not exceed the emission limits of P_{st} ≤ 0.5 (see Figure B.1.2) for the system voltage level concerned. Where expected flicker severity exceeds the limit in Stage 2, then subject to addressing the particular requirements of the system/network operator, the disturbing equipment and/or fluctuating installation may be eligible for Stage 3 assessment.

Stage 3 assessment (see 6.3.4) applies where:

a) emission levels exceed the specified emission limit in Stage 2 despite:

[24] For example: Individual micro inverters that form part of a larger PV system or indoor and outdoor parts of a heat pump installation that work together to form a system.

i. good engineering practice having been followed in the design of the disturbing equipment and/or fluctuating installation; and

ii. reasonably practicable alternative connection points and flicker reduction options having been evaluated and discounted.

b) there is a possibility, based on the system/network operator's knowledge of flicker background levels and any other proposed connection(s), that additional flicker with a P_{st} > 0.5 would result in planning levels being exceeded.

The assessment is such that existing flicker background level and emission levels from the disturbing equipment and/or fluctuating installation at the PCC need to be taken into account. Disturbing equipment and/or fluctuating installations can be connected under Stage 3 providing the available headroom allocated under Stage 3 assessment is not exceeded.

Disturbing equipment connected to the HV system and/or fluctuating installations connected to the HV system should be assessed under Stage 2 and should not be permitted to be assessed under Stage 3 unless the agreement of the system/network operator is obtained.

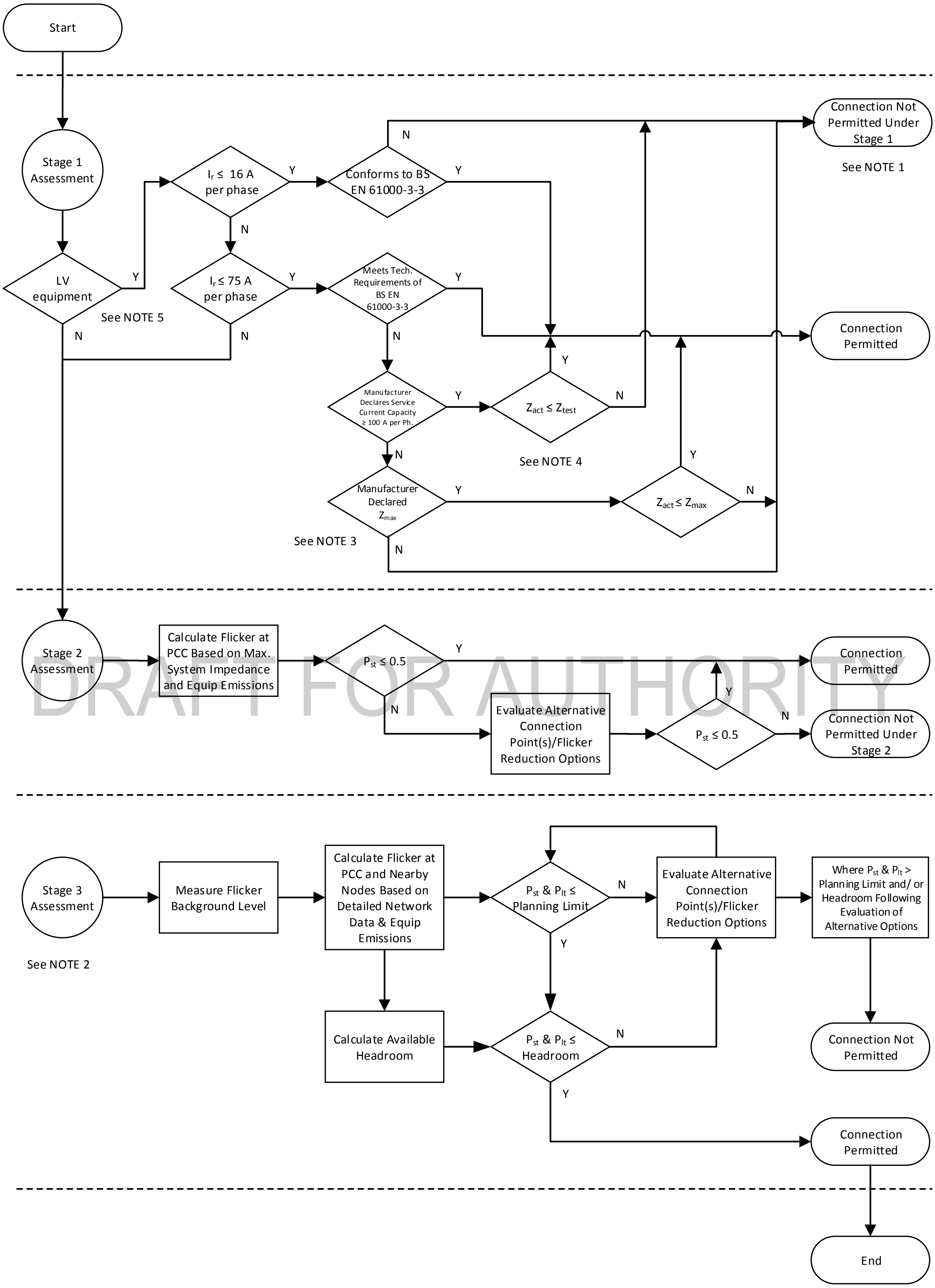

Figure 9 — Three-stage flicker assessment approach

NOTE 1: LV equipment with a rated current (I_r) ≤ 16 A that does not conform to the limits in BS EN 61000-3-3 may be retested and evaluated to show conformance with BS EN 61000-3-11.

NOTE 2: See 6.3.1 concerning the criteria for assessment and connection under Stage 3.

NOTE 3: Zact is the modulus of the actual supply impedance at the customer supply terminals.

NOTE 4: Ztest = 0.15 + j015 Ω for three-phase equipment & Ztest = 0.25 + j0.25 Ω for single-phase equipment.

NOTE 5: Where the PCC is at HV not LV, Stage 1 assessment of LV equipment is not appropriate.

6.3.2 Stage 1 assessment

6.3.2.1 Household appliances and similar electrical equipment

Household appliances and similar electrical equipment with a rated current ≤ 16 A per phase and conforming to BS EN 61000-3-3 are not subject to conditional connection and can be connected to LV public electricity supply systems under this stage without reference to the network operator or further assessment based on LV supply impedance not exceeding the following typical maximum values at the customer supply terminals.

a) Phase-neutral loop impedance of 0.4 + j0.25 Ω ($|Z|$ = 0.472 Ω) for single-phase 230 V connections.

b) Three-phase impedance of 0.24 + j0.15 Ω (|Z| = 0.283 Ω) for three-phase connections.

Interference is very unlikely given network operators design their LV networks to have significantly lower source impedances than those stated in a) and b)[25]. However, it should be recognised that the LV supply impedance of service connections installed pre-1950[26] could be higher than the typical maximum values stated. Where there is doubt whether the impedance at the customer supply terminals is less than the typical maximum values stated then the LV supply impedance should be measured.

Household appliances and similar electrical equipment with a rated current ≤ 16 A per phase but not conforming to emission limits in BS EN 61000-3-3 are subject to conditional connection and can be connected to LV public electricity supply systems under this stage providing they conform to BS EN 61000-3-11 (see 6.3.2.2).

6.3.2.2 Equipment with a rated current ≤ 75 A

Equipment with a rated current ≤ 75 A can be connected to LV public electricity supply systems under this stage without reference to the network operator providing it conforms to the technical requirements in BS EN 61000-3-3 and the service current capacity is confirmed as being adequate for connection of the equipment.

NOTE: Regulation 132-16 of BS 7671 (The Wiring Regulations) requires that the rating and condition of any existing equipment, including that of the network operator, is ascertained as being adequate before any additional or altered equipment is connected.

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[25] LV public electricity systems that are TN-C-S (PME) will typically have a supply impedance ≤ 0.35 Ω.

[26] Services installed pre-World War II and those installed in some council housing estates in the late 1940's and early 1950's could exceed the typical maximum values of LV supply impedance for modern day networks.

Equipment with a rated current > 16 A per phase and ≤ 75 A per phase, not conforming to the technical requirements in BS EN 61000-3-3, is subject to conditional connection and can be connected to LV public electricity supply systems under this stage providing it conforms to the technical requirements in BS EN 61000-3-11.

Equipment that is subject to conditional connection [as required by this clause] can only be connected to the LV public electricity supply system without reference to the network operator providing either:

a) the LV supply impedance at the customer supply terminals is confirmed by measurement (see 7) or from calculated values provided by the network operator as being equal or less than the value (Z_{max}) declared by the equipment manufacturer in the equipment instruction manual; or

b) at the customer supply terminals:

   i. the service current capacity is confirmed as being ≥ 100 A per phase, as required by the equipment manufacturer in the equipment instruction manual, and the equipment has been clearly marked to this effect by the manufacturer; and

   ii. the LV supply impedance is confirmed by measurement as being equal or less than 0.25 + j0.25 Ω (|Z| = 0.35 Ω) for single-phase connections or 0.15 + j0.15 Ω (|Z| = 0.212 Ω) for three-phase connections[27].

The presence of a fuse carrier rated for 100 A per phase does not necessarily mean that the service has a current capacity ≥ 100 A per phase. Where there is doubt regarding the service current capacity at the customer supply terminals or the actual value of LV supply impedance, the installer should contact the relevant network operator for information.

Equipment to be connected to the LV supply system that does not conform to emission limits in both BS EN 61000-3-3 and BS EN 61000-3-11 may be assessed under Stage 2.

NOTE: It is unlikely that disturbing equipment that does not conform to emission limits in both BS EN 61000-3-3 and BS EN 61000-3-11 would meet the limits in Stage 2.

When assessing the suitability of high rated power equipment, i.e. > 16 A per phase, for connection to the public electricity supply system, consideration should be given to: whether the equipment is normally switched infrequently; whether it is designed to avoid unnecessary rapid cycling by control systems; and the magnitude of steady state voltage change to ensure that flicker problems do not arise.

The connection of multiple items of similar LV equipment is addressed in Clause 6.3.2 of BS EN 61000-3-11.

[27] The LV supply impedance for single-phase connections is the phase-neutral loop impedance not the earth fault loop impedance.

6.3.3 Stage 2 assessment

6.3.3.1 General

LV connections that do not come under the Stage 1 assessment process (See Figure 9) and all HV connections should be assessed under the Stage 2 assessment process described in this clause.

Under the Stage 2 assessment process, individual disturbing equipment that is assessed to result in flicker with $P_{st} \leq 0.5$ under the worst case normal operating condition at the PCC can be connected without further detailed assessment[28]. No measurement of existing flicker background level is required for Stage 2 assessment.

An assessment of the P_{st} resulting from connection of the disturbing equipment/fluctuating installation should be conducted. This should be done by simulation, calculation or measurement. Rules to simplify the waveforms generated by particular types of equipment are given in Clause 6.3.3.4.

Simulation of flicker severity from the voltage change characteristics of the disturbing equipment/fluctuating installation being assessed may be carried out using a flicker simulation program providing this accurately simulates the flickermeter in BS EN 61000-4-15[29]. The use of a flickermeter is the preferred method of evaluating flicker severity.

For simple step voltage change patterns or ramp voltage change patterns, or combinations of the two, a simple approximation of P_{st} may be calculated using the 'memory time' technique. The method and examples for calculating P_{st} can be found in Annex G of PD IEC/TR 61000-3-7. Flicker severity should be assessed by simulation if:

a) there is any doubt regarding the values calculated; or

b) the calculated flicker severity is within ±10% of the Stage 2 limit.

Where flicker measurements exist elsewhere for similar disturbing equipment/fluctuating installations to that being assessed, then these measurements may be scaled for the proposed PCC and supply system impedance. The method should follow that in Annex G of PD IEC/TR 61000-3-7, where the ratio of the voltage change is directly proportional to the ratio of the supply system impedance for the worst case normal operating condition at the respective PCCs.

6.3.3.2 Simplified assessment of step voltage changes

The following simplified assessment approach may be applied to most disturbing equipment that causes step voltage changes, ramp voltage changes or simple combinations of these two types of voltage change. Recommendations for assessing other types of voltage change are described in Clause 6.3.3.4.

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[28] Connection of 8 individual disturbing loads each with $P_{st} = 0.5$ and an exponent of $\alpha = 3$ summate to a resultant $P_{st} = 1$. Further information about flicker summation exponents can be found in Table 8.

[29] This Engineering Recommendation does not recommend any particular flickermeter simulation program. However, any party carrying out assessments using flickermeter simulation programs could be required to demonstrate its suitability and accuracy.

The limit of P_{st} = 0.5 for the maximum allowable magnitude of step voltage change with respect to the time between each change is shown by the line in Figure B.1.2.

This limit does not represent the maximum tolerable P_{st} at the PCC but is a value that generally allows individual items of disturbing equipment, which conform to this limit at the PCC, to be connected without any significant probability that the planning level would be exceeded.

Disturbing equipment that results in a flicker severity at any point on or below the line in Figure B.1.2a) can be connected without further detailed assessment.

Figure B.1.2b) is the inverse characteristic of Figure B.1.2a) and shows the maximum number of voltage changes per minute for a given % voltage change.

A step up in voltage followed by a step down in voltage constitutes two separate voltage changes.

Such voltage changes, where the duration between step up and step down are ≤ 1 s are known as 'pulse changes'. Pulse changes can be equated to a single step voltage change for use in Figure B.1.2 using Figure E.1 in PD IEC/TR 61000-3-7.

6.3.3.3 Simplified assessment of ramp voltage changes

Ramp voltage changes are less noticeable in terms of flicker than step voltage changes of the same size.

Figure B.2.5 provides a simplified method for deriving an equivalent step voltage change from ramp voltage changes with different rise/fall times, where the equivalent relative step voltage change is equal to the shape factor (*F*), determined from the characteristic in Figure B.2.5, multiplied by the maximum voltage change (d_{max}).

NOTE: The term d_{max} used in BS EN 61000-3-3 is equivalent to ΔV_{max} used in this EREC.

The acceptability of the voltage change, in terms of flicker, may then be considered as an assessment of simplified step voltage change (see 6.3.3.2).

6.3.3.4 Shape factors

Shape factors may be used for simplified P_{st} assessments for both periodic and non-repetitive voltage fluctuations. Voltage fluctuations of a more random nature, such as those produced by electric arcs, require more advanced techniques for accurate prediction.

In many cases, voltage fluctuations produced by disturbing equipment follow known shapes and predictable patterns. In these cases, the flicker severity that would be produced for a given magnitude of voltage change and shape may be determined using shape factors. These shape factors have been determined from flickermeter simulation programs and can be used in conjunction with the P_{st} = 1 curve to predict P_{st} for known shapes (other than square waveforms).

NOTE: The magnitude of voltage change can be determined from simplified calculations, flickermeter simulation programs or historical data for similar disturbing equipment whereas some knowledge of the operational pattern produced by the disturbing equipment is necessary to evaluate the overall shape of the voltage fluctuation.

The shape factor curves in Annex B may be used for the following fluctuation shapes/patterns.

a) Shape factor curve for pulse and ramp changes.

b) Shape factor curves for double-step and double-ramp changes.

c) Shape factor curves for sinusoidal and triangular changes.

d) Shape factor curve for motor-start voltage characteristics.

6.3.4 Stage 3 assessment

Disturbing equipment that is not permitted to be connected under Stage 2 (see 6.3.3) should be subject to Stage 3 assessment, where agreed by the system/network operator, where a detailed assessment of existing flicker background levels and projected flicker severity should be carried out with the addition of the proposed disturbing equipment/fluctuating installation. In this case the customer should provide all the necessary data to the system/network operator for study purposes (see 6.1.4).

Disturbing equipment and/or fluctuating installations with stochastic voltage fluctuations, such as arc furnaces, should generally be subject to Stage 3 assessment[30].

The flicker background level should, where practicable, be measured at the PCC (see 7.2) during periods the proposed disturbing equipment and/or fluctuating installation is likely to be in operation. Where this is not practicable, the flicker background level may be determined by extrapolation of measurements taken at nearby nodes.

Although the highest flicker level will normally be at the connection point, it could be at another location between the connection point of the proposed disturbing equipment/fluctuating installation and the main source of existing flicker background levels, where existing flicker background levels are high, i.e. P_{st} > 0.5. The method in Annex C of PD IEC/TR 61000-3-7 may be used in conjunction with the flicker transfer co-efficient in Table 3 [of EREC P28] to transfer flicker measured at remote nodes to the PCC under consideration.

Where there is doubt about the location of the highest flicker levels then further measurements of flicker background levels should be taken at other locations. In addition, further modelling should be carried out by the customer to determine the location and magnitude of the highest flicker level. Particular consideration should be given to whether the highest flicker levels can be found on the LV network as a result of:

a) existing high flicker background levels on the LV network; and

b) the additional flicker transferred from proposed disturbing equipment/fluctuating installations to be connected to the higher voltage supply system.

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30 This recommendation does not preclude assessment under Stage 2, where flicker is expected to conform to the limits in Stage 2.

Where there is reason to believe the flicker background level might be relatively high, P_{st} > 0.5 then a direct measurement of the flicker background level at the PCC should be carried out at the pre-connection study stage. A more detailed evaluation of flicker background level may be carried out to identify any scope to reduce flicker levels.

The short-term flicker severity (P_{st}) for the proposed disturbing equipment and/or fluctuating installation should be determined from either:

a) previous measurements of P_{st} for identical disturbing equipment (see NOTE);

b) scaling characteristics of similar disturbing equipment with known P_{st} values;

c) flickermeter simulation[31].

NOTE: A change in network characteristics, e.g. fault level, can affect P_{st} levels even when identical equipment is used elsewhere. The fact that equipment used elsewhere has not resulted in flicker issues does not mean it will continue not to when moved or used at a new network location without assessment.

The effects of any known future connections or system changes, including use of previous measurements of P_{st} for identical equipment used elsewhere, should be assessed[32].

The P_{st} values of the proposed disturbing equipment and/or fluctuating installation, the P_{st} values of any known future connections or system changes and the P_{st} values of flicker background should be summated using the general summation law (see Equation 1).

$$P_{st} = \sqrt[\alpha]{\sum_{i=1}^{i=n} P_{sti}{}^{\alpha}} \qquad \text{Equation 1}$$

where:

P_{st} is the magnitude of the resulting short-term flicker level for the considered aggregation of flicker sources (probabilistic value)

P_{sti} is the magnitude of the various flicker sources or emission levels to be combined

α is an exponent that depends on various factors (see Table 8)

Where the summated P_{st} values exceed the P_{st} planning levels in Table 2, connection of the proposed disturbing equipment and/or fluctuating installation should not be permitted.

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[31] Computer programs that simulate flicker severity are commercially available.

[32] Information about known future connections and system changes can be obtained from Long Term Development Statements (LTDS) published by system/network operators, where available, or on request from system/network operators. This includes the Electricity Ten Year Statement (ETYS) for transmission systems in GB.

The long-term flicker level should be calculated from short-term flicker levels using Equation 2.

$$P_{lt} = \sqrt[3]{\frac{1}{n} \sum_{j=1}^{j=n} P_{stj}{}^{3}} \qquad \text{Equation 2}$$

where:

P_{lt} is the magnitude of the resulting long-term flicker level for the aggregation of short-term flicker levels over the time which P_{lt} is required to be measured (see NOTE)

n is the number of P_{st} values in the time over which P_{lt} is required to be measured

P_{st} is the magnitude of the resulting short-term flicker level for the considered aggregation of flicker sources (probabilistic value)

NOTE: P_{lt} is normally evaluated over a 2 h period, where n = 12.

Where relevant, multiple values of P_{lt} should be summated using the general summation law (see Equation 1) as for P_{st} values. Where the P_{lt} value or the summated P_{lt} values exceed the P_{lt} planning levels in Table 2, connection of the proposed disturbing equipment and/or fluctuating installation should not be permitted.

Where consent is given to connect disturbing equipment or a fluctuating installation following Stage 3 assessment, the system/network operator should measure flicker severity at the PCC following commissioning to verify that the actual measured values are consistent with the assessment and, in the worst case, do not exceed the Stage 3 planning levels. If measurements are made at some other point then the results should be transposed to the PCC, with consideration to using the actual compared with the minimum supply system impedance declared by the system/network operator.

Where two or more applications are received to connect new disturbing equipment/fluctuating installations on the same part of the existing electricity supply system, the extent of interaction and their cumulative effect should be considered. If it is not practicable to connect all of the affected parties without exceeding planning limits, it may be permissible to connect all parties by carrying out mitigating measures. However, following connection of the first party and on-site measurement of the resultant flicker severity levels it might be permissible to connect additional disturbing equipment/fluctuating installations. In such circumstances, the system / network operator will inform all affected parties of the situation and will determine the terms of their connection offers.

Flicker levels should be measured at the PCC, with the disturbing equipment/fluctuating installation:

a) connected to the system/network, i.e. to measure the overall flicker level; and

b) disconnected from the system/network, i.e. to measure the flicker background level.

If the disturbing equipment/fluctuating installation is not connected to a “clean” flicker free system/network, the flicker level should be determined by subtracting the flicker background level from the overall flicker level using the summation law equation (see Equation 1).

Table 8 — Flicker summation exponents

Exponent	Application
$\alpha = 4$	Should be used for the summation of flicker when simultaneous voltage fluctuations are very unlikely to occur (e.g. specific equipment controls are installed so as to prevent simultaneous fluctuations and arc furnaces are specifically run to avoid coincident melts).
$\alpha = 3$	Should be used for the summation of flicker for most types of flicker sources where the risk of coincident voltage fluctuations is small. The majority of studies combining unrelated disturbances fall into this category and it is recommended for general use and when where there is any doubt over the magnitude of the risk of coincident voltage fluctuations occurring.
$\alpha = 2$	Should be used for the summation of flicker when coincident voltage fluctuations are likely to occur (e.g. coincident melts on arc furnaces).
$\alpha = 1$	Should be used for the summation of flicker when there is a very high occurrence of coincident voltage fluctuations (e.g. when multiple motors are started at the same time).
NOTE 1: Applies to the addition of either P_{st} or P_{lt} from various sources. NOTE 2: The lower value of α equates to higher coincidence of voltage changes, where $\alpha = 1$ is the lowest.	

An exponent of $\alpha = 3$ should be used for summation of flicker unless there is information/justification to support the application of another exponent.

There might be applications where using an exponent of $\alpha = 3$ is too conservative, particularly where the risk of coincident voltage fluctuations is very low.

Where the measured flicker background level is $P_{st} > 0.5$ then a more refined method should be used to validate how voltage changes from the fluctuating installation correlate with measured voltage changes.

6.3.5 Simplified voltage change evaluation

For balanced three-phase a.c. electricity supply systems the percentage voltage change caused by disturbing equipment can be derived as follows.

Where the supply system impedance is stated as per unit resistance and per unit reactance values on a base MVA:

$$\frac{\Delta V}{V} = \frac{S}{S_{base}} \left(\cos\varphi \,.\, R_{p.u.} + \sin\varphi \,.\, X_{p.u.}\right) \qquad \text{Equation 3}$$

Where:

ΔV/V Voltage change per unit (p.u.)

S Apparent power change in MVA of the disturbing equipment

S_{base} Base MVA of the supply system impedance

φ Power factor of the disturbing equipment

$R_{p.u.}$ Supply system resistance per unit

$X_{p.u.}$ Supply system reactance per unit

NOTE: Voltage change percent (%) is equivalent to $\Delta V/V$ x 100.

Where the supply system short-circuit power (see 6.1.5) is stated in MVA and the power factor of the load is assumed to be the same as the ratio of supply system resistance to supply system impedance[33]:

$$\frac{\Delta V}{V} = \frac{S}{S_k^{"}} \times 100 \qquad \text{Equation 4}$$

Where:

$\Delta V/V$ Voltage change percent (%)

S Apparent power change in MVA of the disturbing equipment

$S_k^{"}$ Supply system initial symmetrical short-circuit power MVA

Examples of more detailed calculations of voltage changes can be found in Annex G of PD IEC/TR 61000-3-7.

6.3.6 Assessment of equipment against EMC generic standards

Where a dedicated product EMC standard does not exist, then disturbing equipment may be connected to the supply system subject to meeting the requirements and levels for flicker in BS EN 61000 Part 6 Generic standards and with the specific consent of the system/network operator.

Equipment intended to be directly connected to the LV public electricity supply system conforming to BS EN 61000-6-3 shall be subject to Stage 1 assessment (see 6.3.2) as BS EN 61000-3-3 and BS EN 61000-3-11 are normative references in this standard [BS EN 61000-6-3].

Equipment that is supplied from a HV transformer, which is dedicated to the supply of an installation feeding manufacturing or similar plant and is intended to operate in or in proximity to industrial locations, can be connected subject to conformance to BS EN 61000-6-4 and meeting the requirements and levels for flicker stated by the system/network operator.

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[33] This is the worst-case condition.

Where conformance to EMC requirements in harmonised product standards or BS EN 61000 Part 6 Generic standards is not applicable or not appropriate then equipment can be connected to public electricity supply systems via the 'Technical File' path, where it can be shown to conform to the requirements of The Electromagnetic Compatibility Regulations 2016 [1] [34].

NOTE: The 'Technical File' path is a route that manufacturers can opt to follow when declaring conformance to the Electromagnetic Compatibility Regulations 2016. This route is based on relying on evidence assembled within a Technical File by the manufacturer, as opposed to relying on conformance to some or all relevant harmonised standards.

6.4 Assessment of rapid voltage change

6.4.1 General

As a minimum requirement, an assessment to determine the maximum RVC should be carried out:

a) at the minimum fault level for normal operating conditions (see 6.1.6);

b) assuming 0.5 p.u. of remanent flux in transformers[35];

c) assuming the pre-event initial steady state voltage, $V_{0,}$ occurs at the upper and lower statutory voltage limits;

d) at the voltage zero crossing or other point on the voltage waveform, where this results in the maximum magnitude of RVC; and

e) including sympathetic inrush currents between transformers connected in the vicinity unless it can be demonstrated that these currents are insignificant[36].

The assessment procedure should be based on measured changes in r.m.s. voltage refreshed each half cycle starting with the first full cycle of measurements following commencement of the RVC (see 7.3). The first incomplete half cycle measurement following commencement of the RVC should be disregarded.

The maximum RVC should not exceed the relevant limit(s) in Table 4[37].

NOTE: The relevant limits in Table 4 define an envelope for categories of occurrence, which the maximum r.m.s. RVC is required to fit within. The acceptability of voltage change is now assessed over a time period from the start of the RVC event and not just after 30 ms from the start of the event, as was the case in Engineering Recommendation P28 Issue 1.

The magnitude of remanence flux can vary for different types and designs of transformers.

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[34] The Electromagnetic Compatibility Regulations 2016 are the UK implementation of Directive 2014/30/EU of the European Parliament and of the Council relating to electromagnetic compatibility.

[35] In the absence of specific data, a value of 0.5 p.u. remanent flux can be assumed given a value between 0.4 and 0.6 p.u. is typical of measured results.

[36] Sympathetic inrush currents can affect voltage recovery especially in systems/networks with lower fault levels.

[37] Assessment of emission levels is based on the absolute maximum voltage change measured and not the probability the limit could be exceeded for a small period of time.

Where the magnitude of the calculated maximum RVC is marginal, with respect to the limits in this EREC, then the validity of any typical values used, including those for remanence, together with any assumptions should be checked for the particular transformer being studied[38].

6.4.2 Transformer energisation

6.4.2.1 General

Transformer inrush current is asymmetrical with a harmonic content that can last for tens of cycles after transformer energisation. Asymmetry of the inrush current is the result of a d.c. component that can be a significant proportion of the peak current magnitude. For three-phase transformers, at the instant of transformer energisation, the voltage will be different in each phase. Invariably the RVC will be of greater magnitude in one of the phases depending upon the point-on-wave energisation. The maximum voltage change, of the three-phases, should be taken to be ΔV_{max} and used for assessment against the RVC limits in Table 4.

The magnitude of RVC depends on the relative short-circuit capacity of the upstream electricity supply system to the transformer rated power and the inrush characteristic of the transformer. The inrush current characteristic, in terms of the proportion of 50 Hz fundamental frequency current and the initial magnitude and time constant of the d.c. component can vary for different types of transformers.

The study of transformer inrush current is complex and is best done through electromagnetic transient analysis using an appropriate software program. Careful consideration should be given to assigning values to parameters in such software programs.

For example: Magnetising impedance parameters have an important effect on the linear reactance and the decaying time constant related to the magnetic circuit used for estimating the magnetic flux in the core of the transformer.

Studies involving transformer inrush current should consider energisation at a switching angle corresponding to zero volts in one phase[39].

Where the resultant voltage change is marginal, i.e. within 10% of the relevant RVC limit, then energisation at a switching angle corresponding to 5% of the peak rated voltage in that phase should be evaluated[40]. The studies will be acceptable if the resultant voltage change for the latter case is less than 90% of the relevant RVC limit.

Empirical studies show that significant variations can occur in the calculated magnitude of voltage dip depending upon the value of assumed parameters. The sensitivity of the calculated magnitude of voltage dip to changes in parameter values should be understood to ensure the calculated values accurately represent expected measured values.

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38 In practice, remanence values have been found to be lower than 0.8 p.u.

39 Theoretically this represents the worst-case condition.

40 This approach recognises that before the poles of a circuit breaker actually close and touch each other an arc strikes across the poles and current starts flowing in the phase (through the arc). The striking of the arc and flow of current is due to the fact that there is a voltage difference between the circuit breaker poles at that point. Empirically, this voltage is about 5% of the peak rated voltage in the phase when current starts to flow.

6.4.2.2 Simplified assessment

Where detailed information needed to carry out transformer magnetising inrush simulation studies is not available then a simplified assessment may be carried out as a first step to determine whether the magnitude of the voltage dip during energisation is sufficiently close to the RVC limits as to warrant detailed electromagnetic transient analysis.

Simplified assessment can include the following.

- Application of generic curves that relate system fault level to the magnitude of voltage dip for typical distribution type transformers[41].
- Simple modelling of the inrush current from the peak inrush current provided by the manufacturer / supplier and typical constants for different transformer types based on the fundamental frequency component of rated current [42].
- Simple calculation of the magnitude of the initial voltage dip based on the ratio of the peak inrush current to the peak rated current (see Annex C).

It should be noted that using the manufacturer's/supplier's stated peak inrush current as a multiple of rated current might result in an unduly pessimistic magnitude of voltage dip compared with measured results.

The following points should be considered when carrying out simplified assessment.

a) Simplified modelling of the inrush current could underestimate the magnitude of the peak voltage dip by up to 30%, where default values are used and subtransient effects are omitted.

b) The modelling of inrush current decay may differ from that measured in practice given the inrush current decay envelope could be more complex than can be represented by an exponential decay curve and single time constant.

c) The ratio of the peak inrush current and peak rated current can differ appreciably for different types of transformer, therefore it is important to use data that is specific to the transformer being modelled.

d) Dry type distribution transformers will generally result in a greater magnitude of voltage dip on the first energisation than equivalent oil-filled distribution transformers.

e) RVCs are characterised by true r.m.s. voltages not just the power frequency component.

It should be noted that empirically, the magnitude of inrush current and hence voltage dip is generally lower for transformers that comply with BS EN 50588-1, due to lower fixed iron losses.

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41 Such as the Paper 'Assessing P28 Guidelines for Renewable Generation Connections' by R.A. Turner and K.S. Smith [10].

42 Such as the Paper 'A Simplified Method For Estimating Voltage Dips Due To Transformer Inrush', CIRED 20th International Conference on Electricity Distribution, 2009 by Graeme Bathurst [11].

7 Measurements

7.1 General guidelines for measurements

The measurement period should be chosen to include the expected maximum disturbance (flicker severity or RVC) caused by the disturbing equipment/fluctuating installation being assessed.

The measurement period should be generally not less than one week to capture any daily variations in background levels. A shorter measurement period may be used providing this is representative of the measurements that would be expected if measured over one week or would capture the most severe two-hour period of voltage fluctuations (see 7.2.1). In any case, the measurement period should be of sufficient duration to cover at least two full operating cycles of single disturbing equipment and/or at least one full operating cycle for a fluctuating installation with several items of disturbing equipment.

The decision as to whether the limits apply to phase-phase or phase-neutral voltage should be consistent with relevant measurement standards.

Where measurements are taken from systems/networks through a voltage transformer, it is important to give due regard to the phase relationship between measured voltages and LV system/network voltages[43]. This is particularly important for voltage fluctuations which are not symmetrical to all three phases.

Where it is not possible to take measurements under the worst case normal operating condition, the measured values obtained for the particular system/network condition should be analysed to ensure they are consistent with those expected for that condition.

7.2 Flicker measurements

7.2.1 Measurement of flicker severity for an item of disturbing equipment

Direct measurement of all types of voltage fluctuations should be assessed using a flickermeter conforming to the requirements to BS EN 61000-4-15.

Flicker should be measured using the Class A method specified in BS EN 61000-4-30 and BS EN 61000-4-15, except the measurement uncertainty requirement for P_{st} at low modulation rates, i.e. < 40 changes per minute, need only be met for voltage fluctuations ≤ 10% in amplitude over an input voltage in the range of nominal voltage ± 10%. Alternatively, where agreed with the system/network operator, flicker may be assessed using the Class S method for specific applications where the measurement uncertainty requirement is not critical for P_{st} outside the range of 0.4 to 4.

Data should be flagged in accordance with BS EN 61000-4-30 such that abnormal voltage fluctuations[44], e.g. associated with faults or switching events on the network, can be omitted to ensure the measurement is representative of the flicker being assessed.

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[43] This is important as lighting equipment, which is most sensitive to voltage fluctuation, is connected between phase and neutral at LV.

[44] Abnormal voltage fluctuations include those from unintended sources, such as faults etc.

Measurements of P_{st} and P_{lt} should be 95% probability values over a normal measurement period of one week. For shorter measurement periods, 99% probability values for measurements of P_{st} should be used[45].

NOTE: Comparison of 99% and 95% probability values can be useful as ratios > 1.3 can indicate abnormal results caused by voltage dips and transients.

The calculation of P_{lt} should be based on a sliding window of P_{st} values, where the oldest P_{st} value is replaced by the newest P_{st} value at each 10-minute interval.

A check should be made when starting measurements and when interpreting measurement results that step voltage changes are not exceeding 3% between steady state conditions and/or that P_{st} is not exceeding planning levels (see Table 2).

If the disturbing equipment/fluctuating installation is not connected to a "clean" flicker free supply then the measured flicker background level (see 7.2.2), without the disturbing equipment/fluctuating installation in operation, should be subtracted from the result using the general summation law equation (see 6.3.4).

7.2.2 Flicker background levels

Flicker background levels in each phase should be measured without the disturbing equipment/fluctuating installation in operation. The measurement period should be of sufficient duration to obtain typical flicker background levels that coincide with the operation of the proposed disturbing equipment/fluctuating installation. Measurements in the phase with the highest measured flicker background levels should be used for assessment.

A flicker background level of $P_{st} < 0.35$ is negligible and may be discounted in any simplified flicker assessment approach referenced in this EREC.

In the absence of any measured data, the flicker background level should be assumed to be $P_{st} = 0.5$. If there is reason to believe the flicker background level might be greater than $P_{st} = 0.5$, a direct site measurement should be carried out for the purposes of assessment.

Flicker background levels for new substations may be estimated from measurements at other locations in the electricity supply system by applying relevant transfer coefficients from adjacent nodes (see Table 3 for typical transfer coefficients). Examples of how to apply transfer coefficients between different nodes can be found in Annex B of PD IEC/TR 61000-3-7.

7.3 RVC measurements

RVC measurements should be based on measured changes in the r.m.s. voltage.

The worst case RVC measured over the measurement period should be used to determine the emission level, not probability values.

[45] 99% probability values of P_{st} and P_{lt} are not permitted to exceed planning levels.

Instruments used for power quality measurements should conform to BS EN 61000-4-30 and should be capable of Class A measurements, where r.m.s. voltage measurements are refreshed each half-cycle.

It is likely that the actual RVC measured during the measurement period could differ from the value(s) calculated during studies. The difference between actual measured values and calculated values could be explained by one or more of the following.

a) The actual supply system impedance present during the measurement period might be significantly less than for the worst case normal operating condition used for study.

b) Power quality measurement instruments that measure true r.m.s. voltage will include the additional voltage fluctuation caused by harmonic currents; some studies could consider the 50 Hz fundamental frequency only.

c) Switching during the measurement period will not necessarily take place at the worst case condition(s) as studied, e.g. the worst case point on the voltage waveform and/or the worst case remanence flux.

Given actual measured values are dependent on the point on the voltage waveform that a fluctuating installation is energised then a number of repeat energisations should be carried out, where practicable, to validate emission values.

The effect of actual conditions present during the measurement period should be considered when validating measurement results against calculated results and limits in this EREC.

Where possible, measurements should be conducted when the system is fully intact with no outages of equipment and validated against calculated values of RVC for the same system arrangement.

8 Guidance on application

8.1 General

Where full data is available, a simulation of the pattern of voltage changes should be undertaken. Where this is not possible, then the following approximate methods may be used.

When assessing several sources of flicker the resultant value of P_{st} should be determined by application of the general summation law equation (see 6.3.4).

8.2 Supply system considerations

For connected disturbing equipment or fluctuating installations with $P_{st} > 0.5$, the system/network operator should carefully control the connection of further disturbing equipment/fluctuating installations to affected supply systems. This is to prevent planning levels being exceeded in future.

The system/operator should have an effective system in place to identify, record and monitor these affected supply systems.

As it is not practicable to control the connection of certain LV disturbing equipment, in particular, household appliances and similar electrical equipment, the network operator should only consent to the connection of disturbing equipment or a fluctuating installation under Stage 3 if satisfied that other significant loads cannot be connected without their consent.

Where system alterations are contemplated that could change the realistic maximum impedance at the PCCs used for Stage 3 assessments then the system/network operator should re-assess the flicker severity at these PCCs to ensure planning levels are not exceeded.

8.3 Electric motors

As motors can cause voltage changes on starting, during running and on stopping, all these conditions need to be considered when assessing the acceptability of connecting a motor to the supply system.

8.3.1 Starting

In most cases, starting produces the most severe voltage change in terms of both the magnitude and power factor of the current taken. In the majority of cases for motors with direct-on-line starting, the duration of the magnetising inrush current is several seconds.

Where the voltage change characteristic of the starting event fits within the envelope in Figure 5, the acceptability of the minimum time between occurrences may be assessed from Figure B.1.2 and should conform to the recommendations for planning levels and assessment of flicker stated in this EREC.

Where the voltage change characteristic of the starting event does not fit within the envelope in Figure 5, the acceptability of the magnitude of the voltage change should be assessed against the limits in Table 4.

Where a motor is only started at intervals of several months (very infrequent starting event), the voltage change characteristic should fit within the envelope in Figure 7. The system/network operator may insist on special conditions being put in place. These special conditions may include one or more of the following.

a) Restriction of starting to times when the associated system is fully intact with no outages of equipment.

b) Restriction of starting to certain hours, e.g. 0100 hrs - 0700 hrs, to minimise the likelihood of disturbance to other customers.

c) Liaison with the system/network control engineer prior to starting.

d) Consideration of inhibiting tap-changer operation.

Special consideration may be given to other scenarios, where motors will usually only be started over a limited period of the year, generally when there is no lighting load on the system. In these scenarios, although a very limited number of customers might experience the full voltage depression at the PCC, the probability of resultant voltage complaints will be low. Whilst these and similar cases require judgement to be exercised, voltage depressions within the limits of Figure 7 are acceptable.

For motors where the front time associated with starting is short, e.g. ≤ 30 ms, and the tail time is comparatively longer, then the maximum voltage change, d_{max}, can be substituted as the step voltage change in Figure B.1.2.

> Example 1: For a motor with a starting and stopping characteristic lying within the envelope of Figure 5 would need to have a minimum time between starting events of 475 s if the voltage change was 3%.

For direct on line starting the whole cycle may be considered as being equivalent to one step change with the limit taken directly from Figure B.1.2.

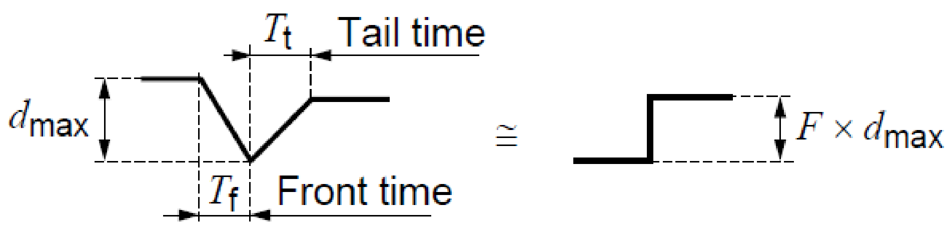
Use of reduced voltage starters, such as star-delta and reactor types, normally causes a second voltage change at the changeover point. This second voltage fluctuation is similar to that in Figure 5 and should be considered equivalent to a further single step voltage change.

For LV motors, where the maximum voltage change ($d_{\max}$), the front time (T_f) and the tail time (T_t) are known then a shape factor (F) can be determined from Figure 5 in BS EN 61000-3-3. The equivalent step voltage change for use in Figure B.1.2 can be obtained by multiplying F and $d_{\max}$ (see Figure 10).

For motors with normal magnetising inrush current characteristics the magnitude of the largest r.m.s. voltage change for starting events can be assessed from either:

a) measurement of the motor current with the rotor locked when supplied at the intended operating voltage of the motor; or

b) reference to the manufacturer's published information.



NOTE: The same convention as BS EN Standards has been followed, where a reduction in voltage is represented as a positive value of d_{max}.

Figure 10 — Application of shape factor (F) for motor starting

For motors with abnormal magnetising inrush characteristics then the voltage fluctuation should be determined from either measurement of similar motor installations or flickermeter simulation programs.

Previous experience has shown that relatively small direct-on-line LV motors can be connected without detailed consideration. These are listed in Annex A.1.

8.4 Furnaces

At the design stage and for single furnace installations, which are effectively electrically isolated from other furnaces, the following simplified assessment may be adopted, generally for connections to 11 kV and 33 kV networks, which involves the calculation of the short-circuit voltage depression at the PCC.

Assuming the source impedance has a negligible effect on the short-circuit power drawn by the furnace, the short-circuit voltage depression may be calculated with sufficient accuracy from the ratio of the furnace steady state apparent short-circuit power in MVA (S_t) and the system short-circuit power in MVA at the PCC (S_c) (see Equation 4).

The apparent short-circuit power of a furnace (S_t) is that power which would be drawn by the furnace if all three electrodes were immersed in molten steel with the furnace transformer tap set to that corresponding to the highest furnace voltage available. The value of S_t may be taken to be twice the furnace rated power if no other information is available.

In order to meet the Stage 2 limit for flicker severity, the value of short-circuit voltage depression calculated from Equation 4 should be less than 1%[46].

Where the effect of source impedance on the short-circuit power drawn by the furnace is not negligible, a more accurate assessment should be conducted.

For induction furnaces, additional aspects of operation, including consideration of voltage fluctuations, are described in Engineering Recommendation P16 [3].

However, the voltage fluctuation limits in EREC P28 supersede any limits in Engineering Recommendation P16 [3].

The cubic summation law in the case of the summation effects of two arc furnaces (at the 95th & 99th percentile) could be too pessimistic for realistic estimation of summation effects and an exponent of $\alpha = 4$ could be considered.

8.5 Heat pumps

Assessment of domestic heat pumps for connection to LV public electricity supply systems should follow the connection/notification process published by the ENA[47]. The voltage fluctuation requirements of that process for connection of a single heat pump/system are equivalent to the Stage 1 assessment process in this EREC (see 6.3.2).

Multiple heat pumps/systems, each with a rated power ≤75 A per phase including any boost or back-up function, for connection to the LV public electricity supply systems, shall be subject to conditional assessment in accordance with Stage 1 of this EREC.

The short-term flicker severity (P_{st}) of fluctuating installations with multiple heat pumps can be summated according to the summation law and exponents in Equation 1 (see 6.3.4) providing that heat pumps start 30 s apart.

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46 This equates to a step voltage change of 1% not more than every 20 s.

47 The notification process for connecting heat pumps can be found on the ENA website.

The general flicker summation exponent $\alpha = 3$ may be used to calculate how many heat pumps can be connected to the same PCC without exceeding the flicker planning level. The flicker summation law and exponents are not valid for multiple heat pumps within a fluctuating installation that are centrally controlled to switch at the same time.

The boost function on multiple heat pumps in the same fluctuating installation should be controlled, where unacceptable voltage fluctuations would occur otherwise if the heat pumps were to switch on/off simultaneously[48].

The indoor and outdoor parts of a heat pump system should be tested as a whole integrated system as well as individual items of equipment. The whole integrated system is required to conform to the emission limits in this EREC.

Special consideration should be given to heat pumps with direct-on-line connection as these could result in excessive voltage fluctuations unless steps are taken to reduce the initial starting current, e.g. using soft-start technology.

8.6 Electric vehicles (EVs)

8.6.1 General

Equipment and systems for charging EVs whether installed in an EV or in a fixed installation should conform to BS EN 61851.

General guidance on the notification process for connecting EV charging infrastructure to LV public electricity supply systems is published by the ENA[49].

The following specific recommendations relate to the assessment of flicker from EV charging equipment.

8.6.2 Fixed charging installations

Fixed charging equipment is not subject to conditional connection and can be connected to LV public electricity supply systems under Stage 1 without reference to the network operator where:

a) the equipment has a rated current ≤ 16 A and it conforms to BS EN 61000-3-3;

b) the equipment is connected at a domestic residence has a rated current ≤ 32 A and it conforms to the technical requirements of BS EN 61000-3-3.

Fixed charging equipment ≤75 A per phase not conforming to BS EN 61000-3-3 should be subject to conditional connection in accordance with BS EN 61000-3-11 and can only be connected to the LV public electricity supply system under Stage 1 if the actual impedance of the supply system the equipment is connected to meets the required value (see 6.3.2).

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48 Some heat pumps are fitted with a boost function that is programmed to operate at specific times. Multiple heat pumps from the same manufacturer, which are fitted with this function, could operate simultaneously if the default time of the programmed boost is not changed.

49 The notification process for connecting EV charging infrastructure can be found on the ENA website.

Network operators should give special consideration to assessment of installations where multiple EV charging connections are proposed to be connected to a PCC. This may include taking steps to prevent simultaneous switching of multiple active chargers to prevent breaching the 3% step voltage change limit.

Where conformance to flicker limits depends upon minimum control cycle time(s) being applied to fixed charging equipment then these should be declared by the manufacturer/supplier and applied to the charging equipment.

The severity of flicker from fixed charging equipment depends, inter alia, on the characteristics of the charger. Where the charging characteristic resembles a stable load with long control cycle times then meeting the 3% step voltage change limit will most probably be the overriding consideration not flicker. Small variations of load whilst charging an EV, even when frequent, are unlikely to result in flicker as opposed to large infrequent step voltage changes when multiple chargers are simultaneously switched on/off.

Special consideration should be given to fixed charging equipment where the main charge has a pulsed current characteristic, given this equipment could significantly increase P_{st} values. This recommendation also applies to chargers that have a maintenance charge function, where the charge is delivered periodically to keep the vehicle battery ‘topped-up’ after the main charge but whilst it is still connected to the charger.

8.6.3 EV on-board chargers

There is no particular requirement to assess flicker from EVs with on-board charging equipment for plug-in connections ≤ 13 A given connections of individual equipment to LV public electrical supply systems with typical supply impedances (see Table 7) have little effect on flicker background levels.

Where the connection of individual EV on-board charging equipment to the LV system results in flicker limits being exceeded, the network operator may require the customer to take steps to prevent interference to other customers.

8.7 Wind turbine generators

Voltage fluctuations from wind turbines connected to the supply system, where the PCC is at HV, should be measured and assessed using the methods in BS EN 61400-21. The measurement procedures in BS EN 61400-21 are valid and may be used for wind turbines connected via three-phases to the LV supply system.

The assessment should consider voltage fluctuations that would arise in continuous operation and during switching operations. Calculations should be based on the power quality information and type test data provided by the wind turbine manufacturer.

For assessing continuous operation of multiple wind turbines within a fluctuating installation, an exponent of $\alpha = 2$ may be used for summation of flicker severity. An exponent of $\alpha = 3.2$ should be used for summation of flicker severity when assessing the effects of switching operations of multiple wind turbines.

When assessing the connection of additional wind turbines to the PCC, steps should be taken to avoid two wind farms performing switching operations at the same time.

Where simultaneous switching operations can be avoided, no summation effects need to be taken into account. Where the risk of simultaneous switching operations cannot be avoided then the resultant voltage fluctuations should be studied and assessed.

Flicker caused by turbulence, wind gusts, tower shadow and oscillation during continuous operation of wind turbines should be assessed, however, these are not expected to be significant for modern Doubly-Fed Induction Generator (DFIG)/full converter connected wind turbines.

When assessing voltage fluctuations caused by wind turbines, particular consideration should be given to switching operations involving fixed speed wind turbine generators and to the energisation of step-up transformers between the wind farm and the supply system.

The connection of the latest wind turbines, with rated powers > 3 MW are unlikely to result in significant flicker when the resultant reduction in local supply system impedance is taken into account. Where the rated apparent power of the wind turbine(s) (S_n) is large compared with the supply system initial symmetrical short-circuit power ($S_k^{"}$), i.e. S_n / $S_k^{"}$ ≤ 3, flicker from the wind turbine(s) may have a significant impact on flicker background levels.

In these cases, an emission limit of P_{st} ≤ 0.35 applies to calculated emissions, where the actual flicker background level is unknown. Where the calculated emission limit is P_{st} > 0.35 but ≤ 0.5, more detailed assessments that take into account actual flicker background levels should be carried out.

8.8 Photovoltaic (PV) installations

Inverter connected PV ≤16 A per phase should conform to the test requirements and limits in BS EN 61000-3-3 and relevant recommendations in ENA Engineering Recommendation G83 [N1].

When assessing flicker from PV installations, flicker severity should be evaluated for various generation outputs from 0% to 100% at power factor conditions that are representative of those likely to be encountered during operation. It is acceptable to assess flicker severity at a constant power factor for PV installations that do not have reactive power control.

NOTE: Generally, residential small scale commercial PV installations export power at unity power factor.

Calculations of flicker should consider those requirements in BS EN 61400-21, for assessing flicker severity from wind turbine generators, that can be applied to assessment of flicker from PV installations. For example, the applicability of the method for assessing the impact of changes to wind speed to assessing the impact of changes in solar energy.

For installations where multiple inverters are proposed, the acceptability of voltage fluctuations arising from variations in generation output caused by changes in solar energy levels should be assessed using a flickermeter simulation program.

Voltage fluctuations caused by the effect of moving clouds on generation output generally result in ramp voltage changes, as opposed to step voltage changes. The effects of moving clouds may be studied but they are unlikely to result in high flicker levels unless the supply impedance at the PCC is untypically high.

The contribution of the customer’s own PV installation to the fault level at the PCC may be considered, where calculated flicker is marginal with respect to flicker limits.

8.9 Energy storage

The ability of energy storage to change rapidly between importing and exporting electrical power has the potential to cause significant voltage fluctuations on the supply system.

Particular consideration should be given to energy storage providing a frequency response function for the supply system as these schemes are designed to produce rapid power swings, which could result in step voltage changes of significant magnitude. There is also a very high probability of coincident power swings between such installations.

Energy storage which provides voltage control/reactive power support can result in small frequent voltage fluctuations that could result in flicker.

Ramping of power changes will assist with meeting step voltage change limits and flicker limits, where significant changes in power occur frequently such as energy storage with low energy rating to power rating. Ramping of power changes is recommended to minimise voltage fluctuations at the PCC.

Where necessary, charging and discharging rates should be limited so as to conform to the voltage fluctuation limits in this EREC.

Energy storage used to balance load to generation can result in increased flicker levels due to its response to a change in customer load and/or generation output. Systems that could significantly increase flicker severity through large step voltage changes following step changes in load or generation should be assessed as a complete system of generation, load and energy storage. Further guidance can be found in ENA EREC G100 [9].

8.10 Household equipment

8.10.1 High power household cooking appliances

Household cooking appliances with rated power > 2 kW but ≤ 4.5 kW may be connected without individual consideration providing that they meet the technical requirements of BS EN 61000-3-3 and/or BS EN 61000-3-11, as appropriate (see 6.3.2.1).

8.10.2 Electrically heated instantaneous shower units

Although electric shower units have high rated powers, compared with most household appliances, their load factor is so small that large numbers can often be accommodated within the supply capacity of an LV network. However, large numbers of electric shower units with the same PCC can cause unacceptable voltage fluctuations on LV networks and it is necessary to regulate their rated power and/or operating characteristics. Electric shower units which conform to the requirements of BS EN 61000-3-11 may be connected without individual consideration (see 6.3.2.2).

8.11 Welding equipment

8.11.1 General

Welding equipment with a rated current ≤ 16 A per phase can be connected to the LV supply system without further consideration providing it meets the requirements of BS EN 61000-3-3.

Welding equipment with a rated current > 16 A and ≤ 75 A per phase, not conforming to the technical requirements in BS EN 61000-3-3, is subject to conditional connection in accordance with BS EN 61000-3-11 and can only be connected to the LV public electricity supply system under Stage 1 if the actual impedance of the supply system the equipment is connected to meets the required value (see 6.3.2).

The following arc-welding and metal-heating plant applications are unlikely to cause appreciable flicker problems on supply systems.

a) Welding equipment with a small rated power compared with that of the supply system impedance, where any additional flicker caused by the welding equipment would be insignificant with that of other large disturbing loads already connected to the PCC. For example: argon-arc machines, atomic-hydrogen machines, wire welders, and miscellaneous small metal-heating machines, such as rivet heaters, installed in moderately large factories.

b) Welding equipment that presents a steady three-phase balanced load on the system for long periods. For example: three-phase a.c./d.c. automatic wire-fed machines and three-phase a.c./d.c. nonferrous welders.

c) Welding equipment fed from motor generators which do not pose any appreciable flicker problems for inherent physical reasons.

The following characteristics of welding equipment are relevant to flicker severity and should be considered in flicker assessments.

a) The magnitude of the sudden steps in welding current that can be imposed on the supply system.

b) Whether the steps in welding current are two-level or multi-level.

c) The power factor of the load increments constituting these steps.

d) Distribution of the welding current in the phase conductors on the HV supply system.

e) The frequency of the resultant voltage changes.

Where welding equipment is connected directly phase-phase at LV, the resultant phase-neutral voltage change[50] can be calculated from the following equation.

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[50] The phase-neutral voltage is more appropriate since lighting is usually connected phase-neutral.

$$\%\Delta V\ (per\ kVA\ of\ welding\ load) = 0.74\ R_s + 0.68\ X_s \qquad \text{Equation 5}$$

Where:

R_s is the resistance of the LV supply system in ohms

X_s is the reactance of the LV supply system in ohms

kVA refers to the manufacturer's stated rated power

$\%\Delta V$ is in the normal range, i.e. 3%

Load power factor is 0.3 p.u. lagging

Each burst of welding current involves two voltage changes

Where welder equipment has a load power factor greater than 0.3 p.u. lagging, the voltage drop on both the lagging phase and the leading phase should be calculated[51].

Generally electric welding equipment is of the arc or resistance type.

8.11.2 Arc welding equipment

Arc welders are, generally, relatively low powered equipment which produce a step change in the system voltage when the arc is struck and another step change when the arc is broken.

Times between the striking and extinguishing of the arc can vary but are usually in the range of several seconds to a few minutes. Problems with flicker severity are only likely to occur when arc welding equipment is connected to a PCC on a 'weak' LV supply system.

8.11.3 Resistance welding equipment

Resistance welders, both due to their size and operating characteristics, can cause severe voltage fluctuations over a wide area of the supply system. Consequently, every effort should be made to check the full range of a resistance welder's likely operating patterns. The voltage changes that each of the pulse size/frequency patterns can cause should be checked using a suitable assessment procedure (see 6.3). Where complex multi-level voltage changes are involved, they should be assessed using a flickermeter or flickermeter simulation program.

Where resistance welding equipment does not incorporate point-on-wave switching control, the voltage change (%ΔV) should be increased by V_m (see Equation 6) to allow for magnetising in-rush.

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[51] Further information on the flicker effects of welding plant, including frequency-changing transformer, d.c. and stored energy types, which are not dealt with by simplified assessment in Equation 5, can be found in ACE Report No 7.

$$\%V_m(per\ kVA\ of\ welding\ load) = 0.50\ R_s + 0.87\ X_s \qquad \text{Equation 6}$$

Where:

R_s is the resistance of the LV supply system in ohms

X_s is the reactance of the LV supply system in ohms

kVA refers to the manufacturer’s stated rated power

Annex A

Connection of LV electric motors

A.1 Motors that can be connected without reference to the network operator

Previous experience has shown that certain relatively small motors detailed in Table A.1 starting direct-on-line can be connected without consideration of flicker or RVC.

Table A.1.1 — Motors started very frequently[1]

Type	Rated Power Output (kW)	Rated Power Input (kVA)
Single-phase 230 V	≤ 0.37	≤ 1.0
Single-phase 460 V	≤ 1.50	≤ 3.0
Three-phase 400 V	≤ 2.25	≤ 4.0
NOTES: 1. Rated power output and rated power input relates to normal running. 2. Motor rated power can be expressed as rated power output (kW) and/or rated power input (kVA)		
[1] Very frequent means started at intervals less than one minute.		

Table A.1.2 — Three-phase motors with the PCC not covered by (a) or (c)

Type	Rated Power Output (kW)	Rated Power Input (kVA)
Single-phase 230 V	≤ 0.75	≤ 1.7
Single-phase 460 V	≤ 3.00	≤ 4.5
Three-phase 400 V	≤ 4.50	≤ 6.00
NOTES: 1. Rated power output and rated power input relates to normal running. 2. Motor rated power can be expressed as rated power output (kW) and/or rated power input (kVA)		
[1] Very frequent means started at intervals less than one minute.		

Table A.1.3 — Three-phase motors with the PCC at the LV busbar of a distribution substation

Distribution Transformer Rated Power (kVA)	Rated Power Output (kW)
200	22.5
300/315	30.0
500	45.0
750/800	50.0
1 000	75.0
NOTES: 1. Rated power output relates to normal running. 2. Applies to motors started at intervals of 10 minutes or longer.	

A.2 Three-phase motors with star-delta starting

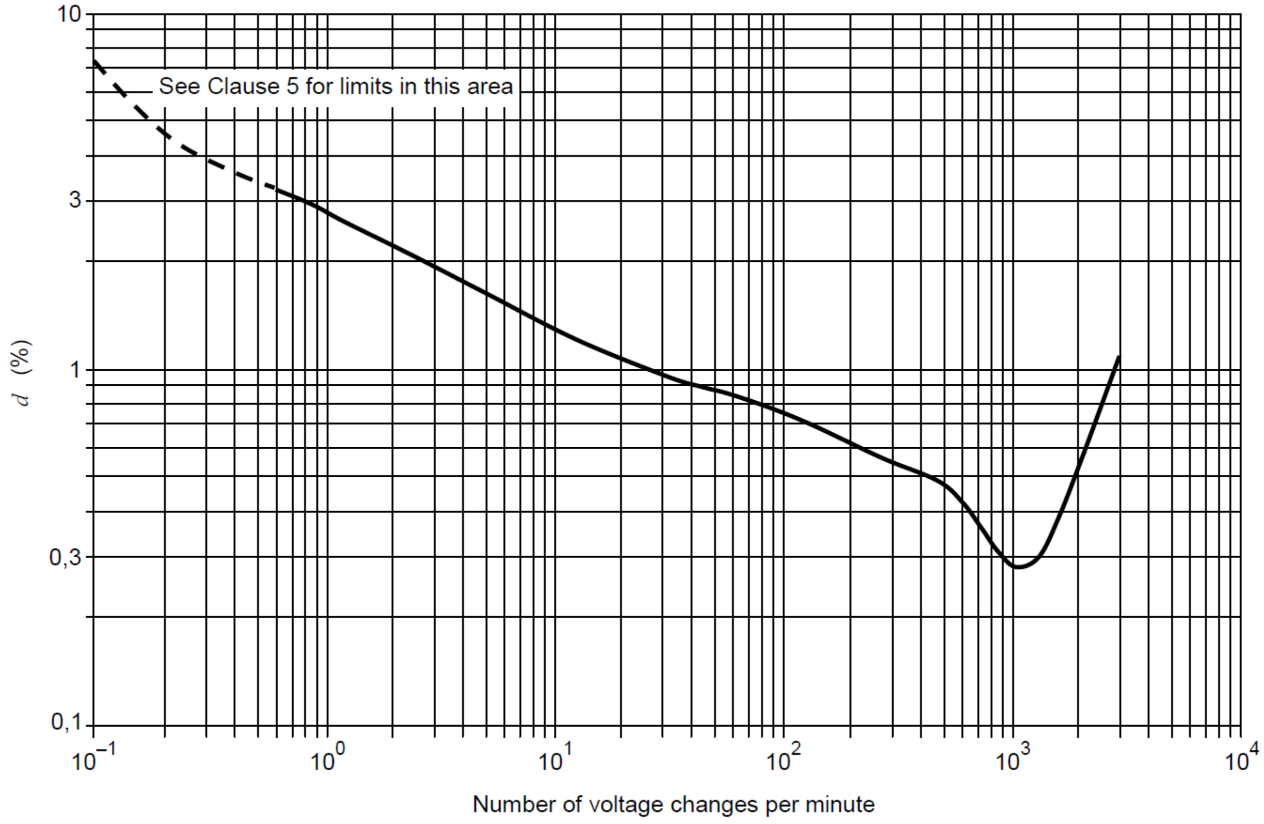
Where star-delta starting is employed, LV motors of up to 1.5 times the rated powers given in Table A.1.1, Table A.1.2 and Table A.1.3 may be accepted without consideration of flicker or RVC.

Annex B

P_{st} curves and shape factor curves

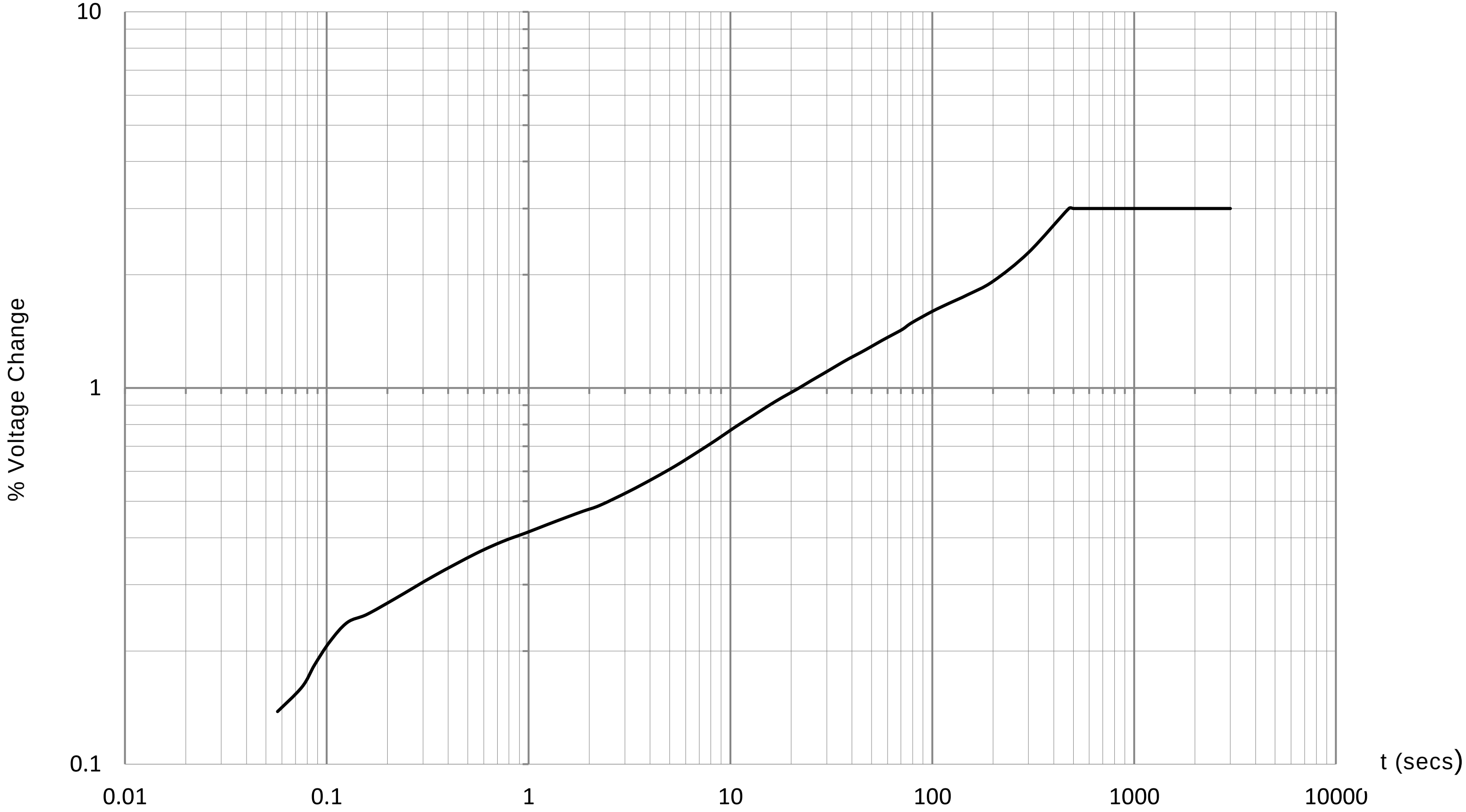
B.1 P_{st} curves

The following P_{st} = 1 curve has been replicated from Figure 2 of BS EN 61000-3-3.



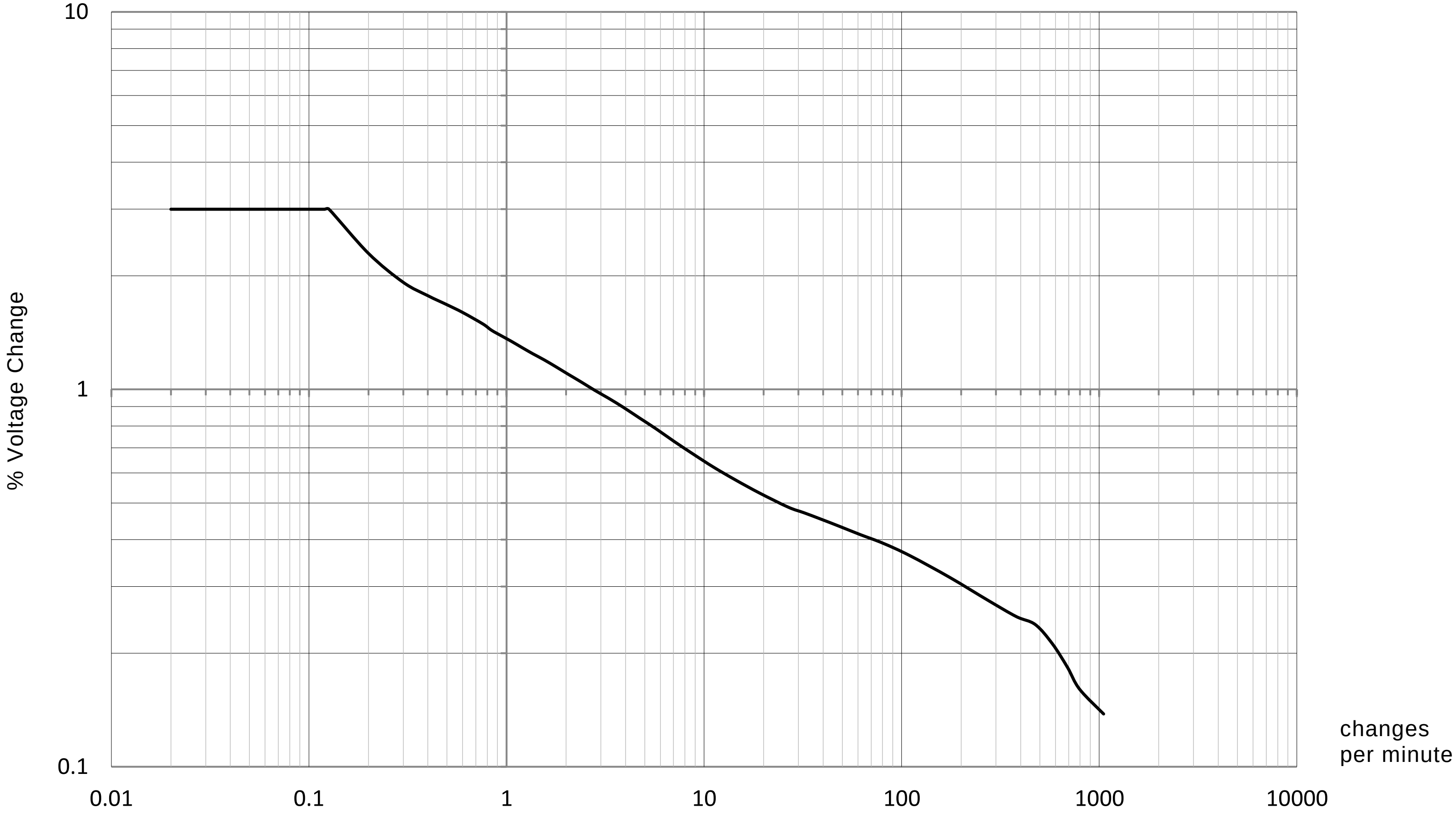
NOTE: ‘Clause 5’ in this figure refers to Clause 5 of BS EN 61000-3-3.

Figure B.1.1 — Curve for P_{st} = 1 for rectangular equidistant voltage changes



a) Minimum time interval between voltage changes

Figure B.1.2 — P_{st} = 0.5 curve for rectangular voltage changes



b) Maximum number of voltage changes per minute

Figure B.1.2 — Pst = 0.5 curve for rectangular voltage changes

Notes for Figure B.1.2

NOTE 1: The P_{st} = 0.5 curve is derived from the P_{st} = 1 curve in Figure A.1 of PD IEC/TR 61000-3-7, given the linear relationship between the value of P_{st} and the magnitude of voltage change. For example: a 2% step voltage change that would give P_{st} = 1 equates to a 1% step voltage change at P_{st} = 0.5 at the same frequency of occurrence.

NOTE 2: The P_{st} = 0.5 curve has been deliberately capped at a maximum symmetrical step voltage change of 3% once every 475 secs given the simplified nature of assessment.

NOTE 3: % voltage change represents the magnitude of a relative voltage change with a rectangular (step) voltage characteristic expressed as a percentage of the nominal system voltage (V_n).

NOTE 4: Figure B.1.2 replaces Figure 4 in P28 Issue 1.

B.2 Shape factor curves

The following shape factor curves have been replicated from Annex E of PD IEC/TR 61000-3-7 and Clause 6 of BS EN 61000-3-3.

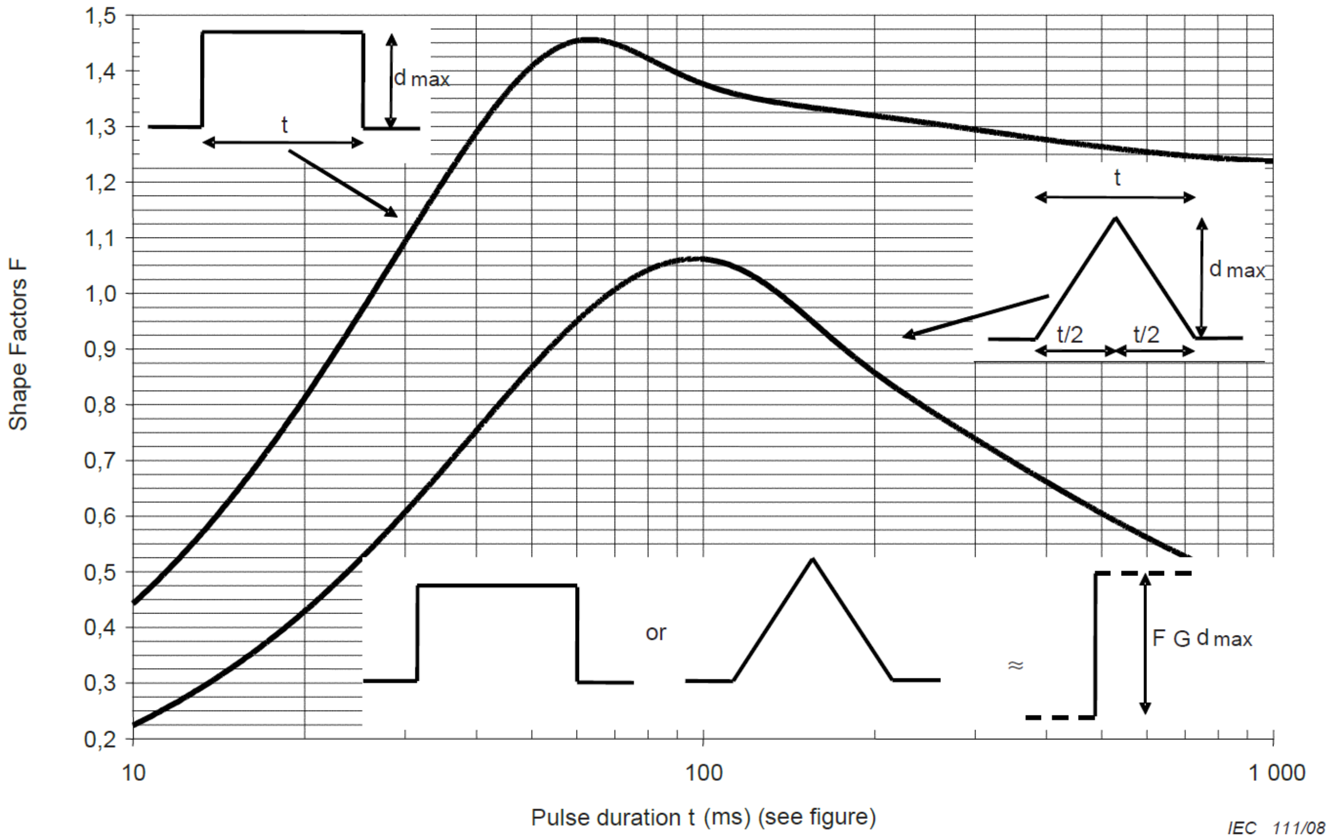


Figure B.2.1 — Shape factor curve for pulse and ramp changes

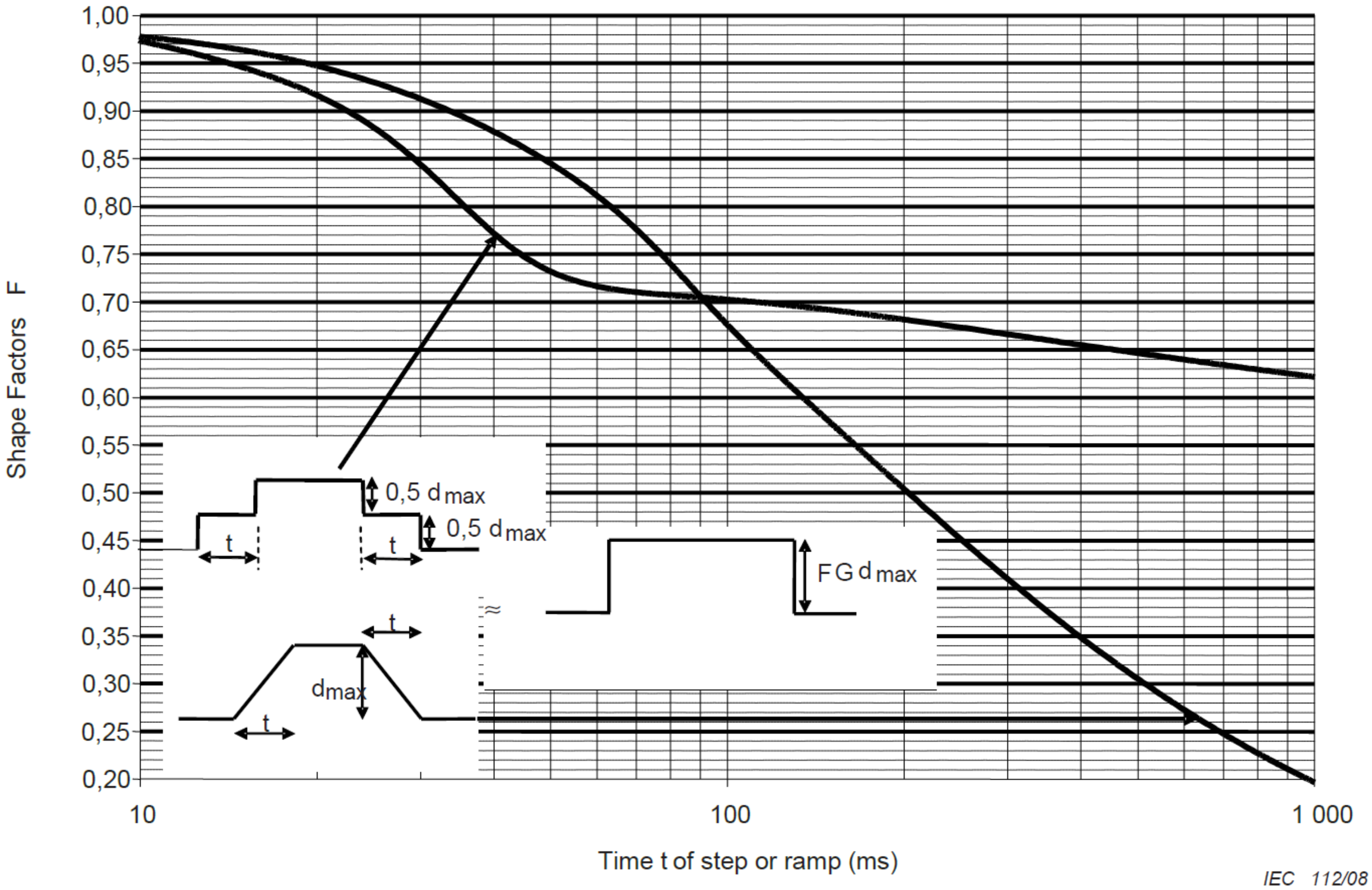


Figure B.2.2 — Shape factor curve for double-step and double-ramp changes

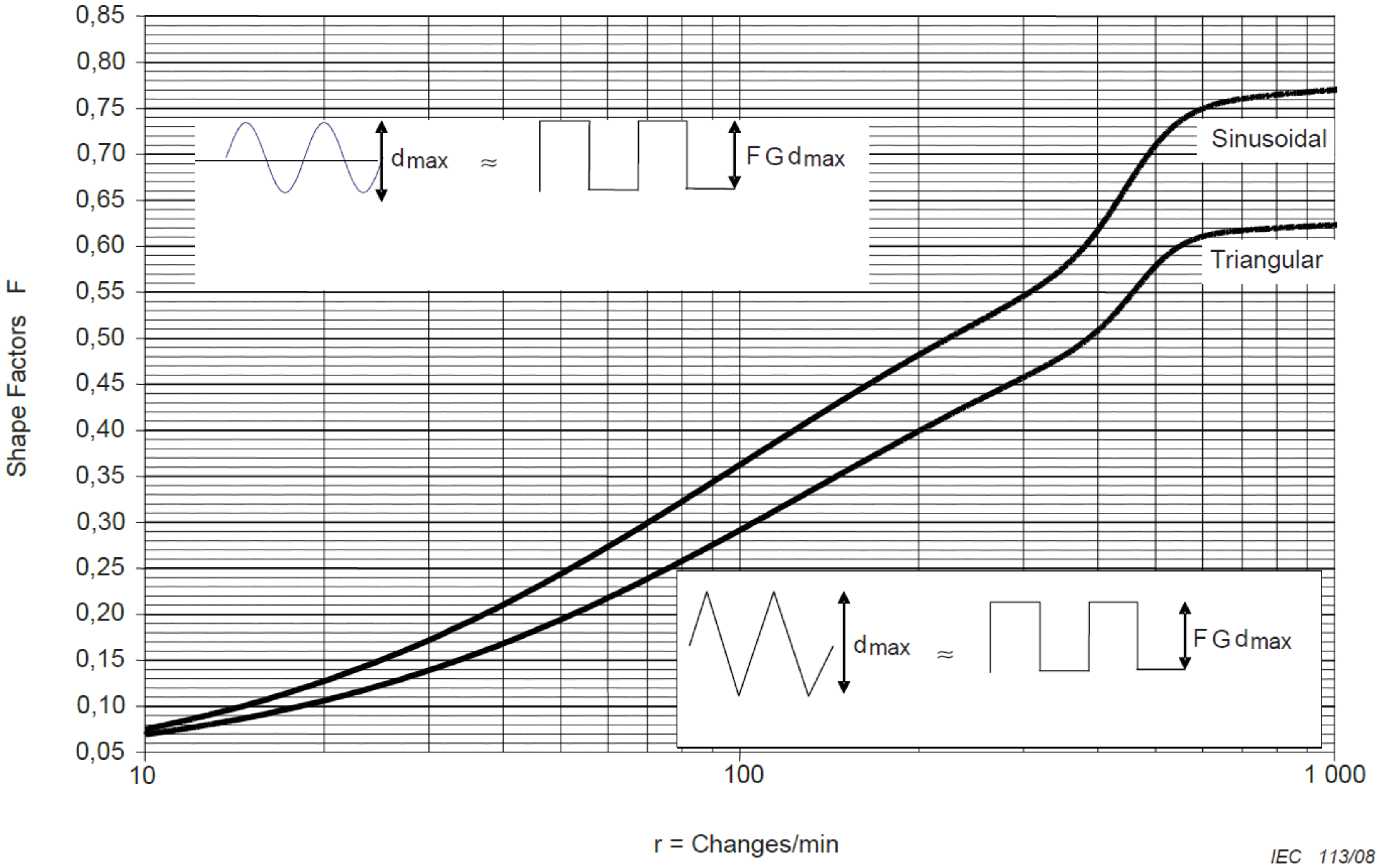


Figure B.2.3 — Shape factor curve for sinusoidal and triangular changes

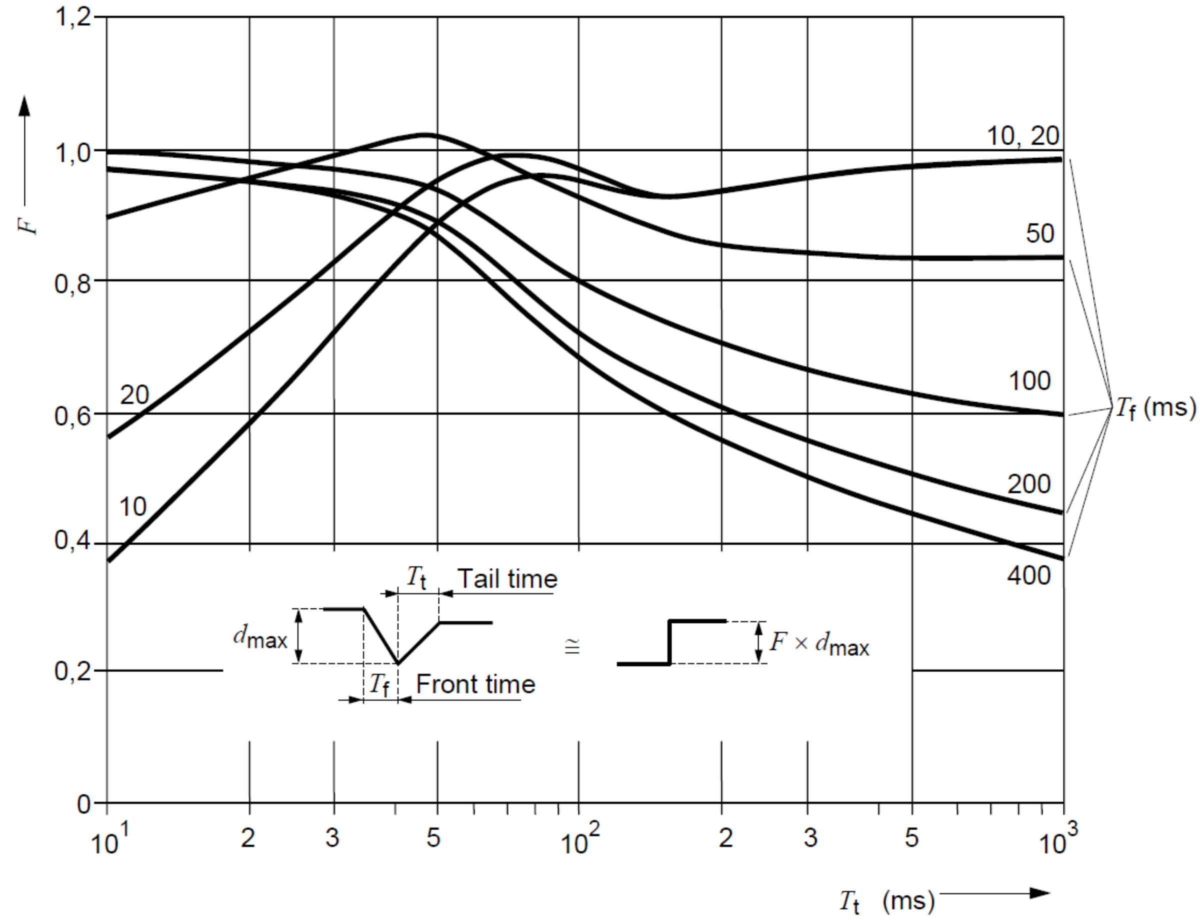
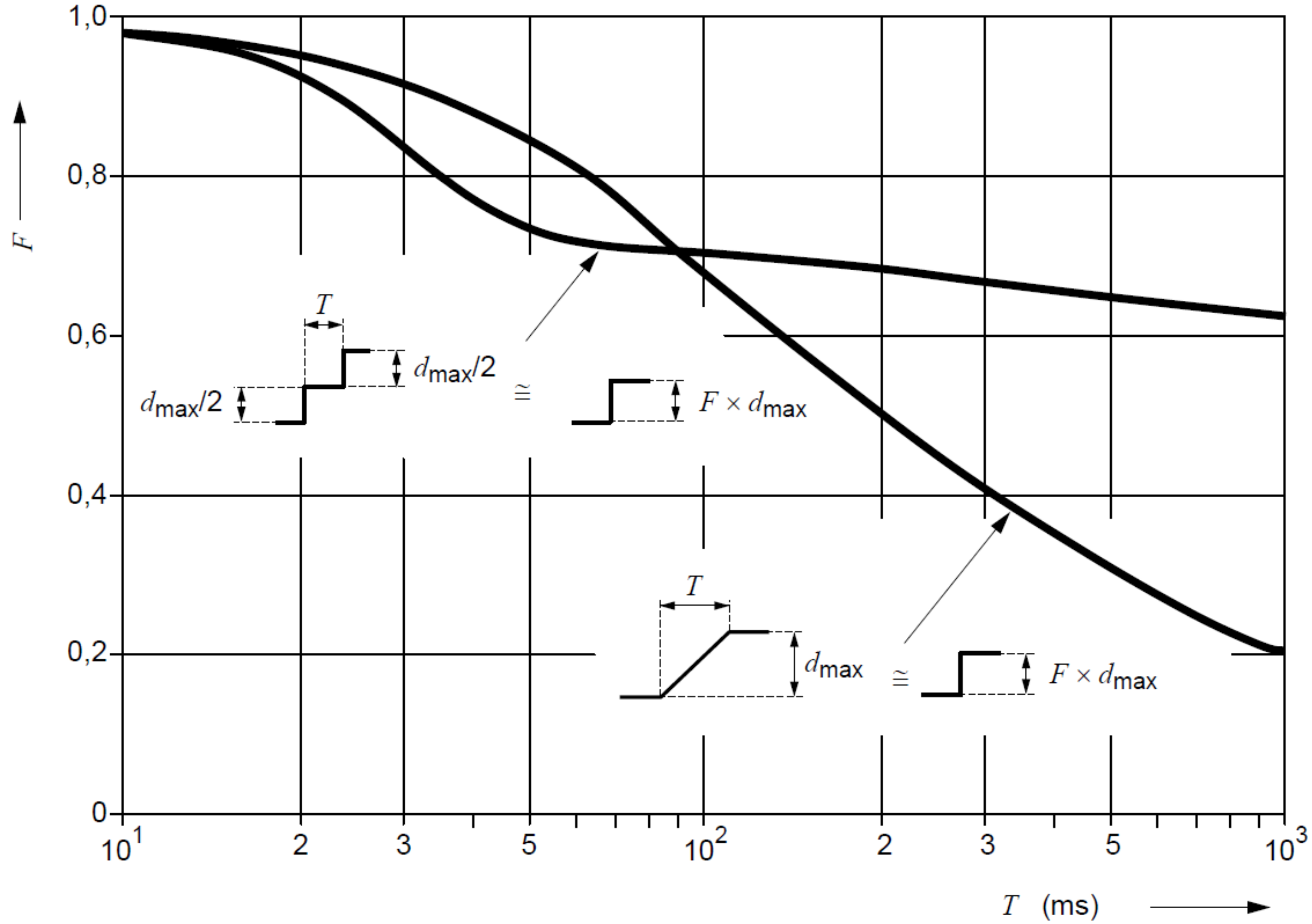


Figure B.2.4 — Shape Factor curves for motor-start characteristics having various front times



NOTE: Equivalent to Figure 3 in BS EN 61000-3-3.

Figure B.2.5 — Shape factor (*F*) for ramp type voltage characteristic

Annex C

Simplified calculation to estimate voltage change due to inrush current

C.1 Introduction

Where it is necessary to estimate the approximate voltage change due to magnetising inrush current, a simplified calculation (Equation C.1 in this Annex) can be carried out as a first step.

This calculation is not a substitute for detailed electromagnetic transient analysis but can help to determine whether the magnitude of the initial voltage dip during energisation is sufficiently close to the RVC limits as to warrant detailed electromagnetic transient analysis.

This calculation estimates the initial voltage change (decrease) only and does not give any indication of the voltage characteristic of the voltage recovery.

If the estimated voltage change is well within the RVC envelopes (see 5.3.2), it is likely that the energisation would be compliant with limits for RVC in this EREC.

This calculation is applicable to transformer energisation, motor start, and other inrush currents with similar behaviour.

C.2 Simplified calculation

$$\%\Delta V = m \times k \times \frac{S}{S_{sc}} \times 100 \qquad \text{Equation C.1}$$

Where:

$\%\Delta V$ is the percentage voltage change

m is the ratio of peak inrush current to peak rated current

k is a factor to convert the peak value of the inrush current to a r.m.s. value

S is the rated power of the transformer or motor

S_{sc} is the short-circuit power of the supply system

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[1] *The Electromagnetic Compatibility Regulations 2016*

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[6] Statutory Instrument 2002 No. 2665, *The Electricity Safety, Quality and Continuity Regulations 2002*: http://www.legislation.gov.uk/uksi/2002/2665/made

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[12] Commission Regulation (EU) No 548/2014 of 21 May 2014 on implementing Directive 2009/125/EC of the European Parliament and of the Council with regard to small, medium and large power transformers