Guidance Notes for Synchronous Generators

September 2008 – Issue 11

Foreword

These Guidance Notes have been prepared by the National Grid plc to indicate to Generators the manner in which they should:

(i) Record compliance with the Grid Code, and Site Specific Technical Conditions in the Bilateral Agreement (BA).
(ii) Demonstrate such compliance to National Grid, through testing as required.

These Guidance Notes are prepared, solely, for the assistance of prospective Generators connecting directly to the GB Transmission System or Large Embedded Power Stations. In the event of dispute, the Grid Code and Bilateral Agreement documents will take precedence over these notes.

Small and Medium Embedded Power Stations should contact the relevant Distribution Network Operator (DNO) for guidance.

These Guidance Notes are based on the Grid Code, Issue 3, Revision 29, effective from the 1 September 2008. They have been developed from Issue 11 Draft 1 of the Guidance Note of February 2007 and reflect the major changes brought about by Grid Code revision G/06 as finally approved by the regulator.

The Grid Code Review Panel has convened a working group to develop the processes and demonstrations of compliance contained in this guidance note for inclusion in the Grid Code. Details of the meetings of this working group can be found on the National Grid information website associated with the Grid Code. The conclusions of the working group will be subject to a consultation before inclusion in the Grid Code. It is currently expected that most of the content of this Guidance Note will be covered by the updated Grid Code with the exception of information for manufacturers covered in Chapter 3. This note will be updated, once the proposals on the Grid Code modifications have been reviewed and accepted by the relevant parties.

Definitions for the terminology used this document can be found in the Grid Code.

National Grid staff will be happy to provide clarification and assistance required in relation to these notes and on Grid Code compliance issues.

CONTENTS

ABBREVIATIONS

This section includes a list of the abbreviations that appear in this document.

Abbreviation	Description
AVC	Automatic Voltage Control (on transformers)
AVR	Automatic Voltage Regulator
BA / BCA	Bilateral Agreement / Bilateral Connection Agreement
BC	Balancing Code
BM / BMU	Balancing Mechanism / Balancing Mechanism Unit
CC / CC.A	Connection Conditions / Connection Conditions Appendix
CC.A	Connection Conditions Appendix
CCCR	Connection Condition Compliance Report (now obsolete)
CCGT	Combined Cycle Gas Turbine
CUSC	Connection and Use of System Code
DCS	Distributed Control System
DNO	Distribution Network Operator
DMOL	Design Minimum Operating Level
DPD	Detailed Planning Data
DRC	Data Registration Code
EDL/EDT	Electronic Data Logging / Electronic Data Transfer
ELEXON	Balancing and Settlement Code Company
FON	Final Operational Notification
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GCRP	Grid Code Review Panel
GT	Gas Turbine
ION	Interim Operational Notification
LSFM	Limited Frequency Sensitive Mode
LON	Limited Operational Notification
MEL	Maximum Export Limit
MLP	Machine Load Point
NGET	National Grid Electricity Transmission
OC	Operating Code
OCGT	Open Cycle Gas Turbine
OEL	Over Excitation Limiter
OFGEM	Office of Gas and Electricity Markets
PC	Planning Code
PSS	Power System Stabiliser
PSSE	Power System Analysis Software
RISSP	Record of Inter System Safety Precautions
SEL	Stable Export limit
SO	System Operator (National Grid)
SPT	Scottish Power Transmission
SHETL	Scottish Hydro Electric Transmission Limited
ST	Steam Turbine
STC	System Operator Transmission Owner Code
TO	Transmission Owner
TOGA	Transmission Outages, Generation Availability
UDL	User Data Library
UEL	Under Excitation Limiter

1 INTRODUCTION

This document provides an overview of the preferred connection process Generators may follow to achieve and maintain Operational Notification. Operational Notification is required to allow generators to synchronise and export power onto the public electricity system. In addition the document describes in greater detail technical studies and testing which demonstrate compliance with the Connection Conditions section of the Grid Code.

To achieve Operational Notification the generator must demonstrate compliance with the Grid Code and Bilateral Agreement. The Grid Code is a generic document which specifies requirements regardless of local conditions. The Bilateral Agreement is a site specific document agreed by National Grid and the Generator, which for technical reasons, may specify additional/alternative requirements. The total requirements placed on Generators are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

All compliance evidence, test results and associated data are to be compiled into a single report referred to from here on, as the User Data Library (UDL). The User Data Library provides a convenient framework for generators to submit data. It replaces the Connection Conditions Compliance Report (CCCR) which was previously used to compile such data. Depending on the nature of the data in the various subsections of the User Data Library, the System Operator (SO) or Transmission Owner (TO) will take the compliance lead role.

This particular edition of the guidance notes has been written for conventional synchronous generation technologies. A separate document exists for new generation technologies based on asynchronous plant.

Generators may, if they wish, suggest alternative tests or studies, which they believe will demonstrate compliance in accordance with the requirements placed on themselves and National Grid.

2 COMPLIANCE PROCESS

This section provides an overview of the compliance process, associated milestones and lifetime compliance issues.

2.1 Scope

National Grid will manage the Compliance Process for all transmission connected power stations and embedded large power stations; this guidance note covers these classes of station. For embedded medium and small power stations the relevant Distribution Network Operator (DNO) is responsible for the compliance process and the User should therefore consult the relevant DNO. The DNO is also responsible for forwarding the relevant data to National Grid and the Transmission Owner.

The current Grid Code classifies all Power Stations based on their Registered Capacity (RC), as follows:

England & Wales (NGET Area)	- Large ≥ 100MW, Medium ≥ 50MW, Small < 50MW
South of Scotland (SPT Area)	- Large ≥ 30MW, Small < 30MW
North of Scotland (SHETL Area)	- Large ≥ 10MW, Small < 10MW

2.2 Responsibilities and Requirements

The process detailed in this document will be managed by the ‘National Grid Electricity Customer Manager’ (see Appendix I of this document). This manager will be responsible for accepting all documents from the User and for issuing all documents by National Grid.

The Electricity Customer Manager will appoint a member of his staff, currently known as the Commercial Contact to streamline this process and provide a single point of contact for the Generator.

The Commercial Contact will supply a site specific tick sheet identifying the expected timescales for the various actions in this compliance process.

A nominated lead engineer from 'National Grid Generation Dynamic Performance', known as Compliance Engineer (CE), will co-ordinate, witness and record any testing or monitoring required.

The Generator will be responsible for self certifying the compliance statements, submitting all data, carrying out tests and simulation studies. The self-certification of the compliance statements and the submission of data are described in the following sections. Required tests and simulations studies are discussed in detail later in this Guidance Note.

The English language should be used in all correspondence and documents submitted to National Grid.

An Operational Notification is required to allow generators to synchronise and export power onto the national transmission system. Operational Notification is issued by National Grid in one of three categories, Interim, Final or Limited. The Interim Operational Notification (ION) is time limited and exists purely for the purpose of commissioning new plant. Final Operational Notification does not place time limits on the operation of the plant. To achieve Final Operational Notification (FON) the generator must demonstrate compliance with the Grid Code and Bilateral Agreement. Limited Operational Notification (LON) is time limited and is used for rectification of non compliant plant which previously had a FON. The timing, requirements and circumstances for issuing these notifications are detailed later in this document.

2.3 Self-Certification

All Generators are required to self certify, with suitable supporting evidence, that their equipment is compliant with Grid Code and Bilateral Connection Agreement.

The Bilateral/Construction Agreement between National Grid and the User places an obligation on the User to submit certifying statements to National Grid that, to the best of the information, knowledge and belief of the User, all relevant Grid Code conditions applicable to the User have been complied with. Certain Grid Code conditions refer to the Bilateral Agreement, in which the specific requirements of the particular connection are set.

To streamline the process National Grid will provide a site specific compliance statement pro-forma for each new generation project, which are to be completed by the Generator. In addition National Grid will provide a pro forma summary front sheet which should be used by the Generator to highlight any non-compliance issues

Appendix H of this document shows a sample summary front sheet and the specific compliance statements for a synchronous generator connection.

2.4 User Data Library

The User Data Library replaces the Connection Conditions Compliance Report (CCCR) which was used to compile all such data previously.

The User Data Library provides a common directory structure where information in support of compliance statements can be submitted, shared and commented upon. The empty directory structure of the UDL will be provided by National Grid. The structure of UDL is given in Appendix B of this document. In addition, it also shows for each subsection who will take the lead role for reviewing submitted data, and who will share that data. For embedded Power Stations, the lead role taken by the Transmission Network Owner (TO) will be transferred to the Distribution Network Operator (DNO) and any data shown to be shared by the TO will be shared by the DNO and TO.

In the NGET Transmission Area, NGET is the Transmission Network Owner and System Operator. It is also the System Operator for Scottish Power Transmission (SPT) Area and Scottish Hydro Electric Transmission Ltd (SHETL) Area. Scottish Power is the Transmission Network Owner in SPT Transmission Area and Scottish and Southern Electricity is the Transmission Owner in SHETL Transmission Area. In the case of off-shore installations NGET is the System Operator. Depending on the location of the off-shore installations, the connection may be owned by a Distribution Network Operator or a TO and the lead role and data sharing arrangements will be the same as that for an embedded power station.

At the end of this compliance process the UDL should contain data as per as the installed and tested plant. Consequently the UDL can only be completed at the end of this process. In the beginning the UDL will have signed legal agreements and the Committed Project Planning Data required by the Planning Code. As the process develops it will be updated. The nature of the data required at each stage of the process is described later in this document.

2.4.1 Format of Data

Generators are requested to submit all data in standard formats for incorporation into National Grid's information management system and forwarding to relevant TO where necessary.

Unless otherwise agreed submissions should be in the following file formats.

- Specifications, Statements, Agreements and Technical Reports in PDF format
- Signed Documents in scanned PDF format.
- Test result data points in XLS format (e.g. Excel ®)
- Performance Charts/Plots PDF and/or XLS format.
- Drawings in PDF or DWG format.
- Simulation Models in transfer function block diagrams (PDF or DWG format).

Where documents and diagrams are provided as supporting information, they should be legible and should include all relevant data assumptions (for example generator base, p.u., percentage values etc).

Where testing and monitoring results are provided they should be legible, appropriately sized, scaled and labelled.

2.4.2 Media Formats

At the time of writing the preferred format for submitting this information to National Grid is compact disk. Submitted compact disks should have the version number printed or written on them and should contain a revision history indicating what has changed from version to version. Users should be aware that other methods of submitting the information are currently being considered including via the National Grid website. Announcements relating to future developments in this area will be made via National Grids website.

2.5 Process Documentation

The following documents are used by National Grid to formally clarify the status of the Power Station as it progresses through the commissioning process. If required, the Commercial Contact can provide a pro forma for each of the statements to be provided by the Generator (1, 6, 8 and 9 below, as applicable).

Note: The documents are applicable to Power Stations that are directly connected to the Transmission System and Large Embedded Power Stations. Medium and Small Embedded Power Stations should contact the Distribution Network Operator.

1) 'Statement of Readiness to Commence the Commissioning Programme', submitted by the Generator, endorsed by Transmission Owner. This provides notification that the Generator is now ready to commence the Commissioning Programme referred to in the Construction Agreement.

2) Statement of Readiness to Complete the Commissioning Programme, submitted by the User, endorsed by Transmission Owner.

3) Transmission connected Generators only: 'Statement of Completeness and Readiness to Energise High Voltage Equipment', submitted by the Generator, endorsed by Transmission Owner. This provides notification that equipment has been tested and inspected and is now ready for energisation and on-load commissioning tests.

4) Embedded Large Generators only: 'Statement of Completeness and Readiness to use the GB Transmission System', submitted by the Generator, endorsed by Distribution Network Operator. This provides notification that the Generator is ready to energise the connection to the Distribution Network and use the GB Transmission System.

5) 'Energisation Notice': This provides notification that National Grid or Distribution Network Operator agree that the Substation can be energised for the purpose of commissioning the Power Station and taking demand (power) from host network.

6) 'Notification of Users Intention to Synchronise', submitted by the Generator, endorsed by Transmission Owner. This provides notification that the Generator is ready to complete the Commissioning Programme, in respect of the works prior to synchronisation. At this point the Generator is expected to submit the Connected Planning Data and a report certifying that to the best of the information, knowledge and belief of the Generator all relevant Grid Code Conditions and site specific technical conditions applicable to the Power Station have been complied with.

7) 'Interim Operational Notification', provided by National Grid. This provides notification that National Grid is satisfied with the interim compliance evidence and the Generator may synchronise. Interim Operational Notification will be time limited to cover the commissioning and compliance demonstration period and may include operational constraints. Extensions to the Interim Operational Notification period may be available for reasonable circumstances.

8) 'Final Operational Notification' provided by National Grid.

9) 'Limited Operational Notification' provided by National Grid.

2.6 Overview of Connection, Energisation and Synchronisation Process

The Generator starts the process with an application for a Connection and Use of System Code (CUSC) contract with National Grid. The transmission constructed work will be covered by an agreement between System Operator and the Transmission Owner. At that time the applicant has to submit Standard Planning Data as specified in Part 1 of Appendix A in the Planning Code section of the Grid Code.

Following the signing of a CUSC contract a commissioning programme is agreed upon. The Generator also agrees to provide statements of readiness and notifications to proceed, at key milestones within the commissioning program (Refer Section 2.5 above).

National Grid will provide the following to start the process:

- A site specific tick sheet identifying the expected timescales for the various actions.
- Compliance statements for each new Connection, which are to be completed by the Generator.
- Pro forma summary front sheet which should be used by the Generator to highlight any known or potential non compliance issues.
- Required User Data Library structure.

Stage 1 – Submission of Detailed Planning Data

The Grid Code (Part 1 of Appendix A in the Planning Code) specifies that the detailed planning data (DPD) should be submitted within 28 days of accepting the CUSC contract. Part 3 of the UDL is the repository for such data.

Stage 2 – Commissioning of the Network Plant
The generator should notify National Grid of the start of commissioning phase, by submitting the 'Statement of Readiness to Commence the Commissioning Programme' (Document 1 in Section 2.5) endorsed by Transmission Owner or Distribution Network Operator.

The Generator may have a supply from the local Distribution Network Operator for most of the commissioning work but the plant is not considered "energised".

Similarly the generator should notify National Grid the completion of commissioning phase, by submitting the Statement of Readiness to Complete the Commissioning Programme (Document 2 in Section 2.5), endorsed by Transmission Owner or Distribution Network Operator.

Stage 3 – Energisation Process
Energisation is an important milestone in the compliance process. It marks the energisation of the new busbars on to which the new generation will be connected. The day this takes place is referred to as the Completion Date.

Before Energisation could take place, the following conditions have to be met.

- All Commercial & Legal documents listed in Part A of the UDL are agreed and listed in the UDL
- The power station Safety & System Operation arrangements have been endorsed, mainly by the host TO or Distribution Network Operator and some by the SO. This is fully covered by Part 1 of UDL
- The Connection Technical Data has been submitted as Part 2 of the UDL and endorsed by TO, SO and Elexon as indicated in the UDL structure.
- All DRC Schedules listed in Parts 3 and 4 of the UDL are completed with Connected Planning Data.

NB Guidance on submitting the DRC schedules can be found in the document "Guidance Notes for Network Operators – Submission of Grid Code Data 2006/2007" which can be obtained from the National Grid web site.

In summary Parts A, 1, 2 and 4 should be submitted and endorsed by the party taking the compliance lead role for each of the subsections in the UDL.

When a transmission connected Generator has successfully submitted the above data and had them endorsed then the 'Statement of Completeness and Readiness to Energise High Voltage Equipment' (Document 3 in Section 2.5), should be submitted to National Grid by the Generator, endorsed by the Transmission Owner and any other affected Transmission Owners if necessary.

If National Grid accepts this statement, it will then issue the 'Energisation Notice' (Document 5 in Section 2.5. This provides notification that National Grid agrees that the Substation can be energised for the purpose of commissioning the Power Station and taking demand (power) from the host network.

Similarly when an embedded Generator has successfully submitted the above data and had them endorsed then the Statement of Completeness and Readiness to use the GB Transmission System (Document 4 in Section 2.5), should be submitted to the Distribution Network Operator. In this case the Distribution Network Operator will issue the Energisation Notice to the embedded power station.

Stage 4 – Synchronisation Process
Following energisation and completion of all commissioning of the plant, the generator will be ready to synchronise and export power.

In the case of synchronous generators some commissioning tests like Excitation System Open Circuit Step Response Tests and measurement of Open & Short Circuit Saturation characteristics take place before synchronisation.

Some commissioning takes place following synchronisation. When the Generator has completed all other commissioning prior to synchronising, the Generator is expected to submit the Connected Planning Data in Part 3 of the UDL and self certifying compliance statements. A 'Notification of Users Intention to Synchronise', will be submitted by the Generator and endorsed by the Transmission Owner.

As synchronisation always follows energisation, at this stage National Grid should have all parts of UDL including self-certifying compliance statements with a Pro forma summary front sheet highlighting any known or potential non compliance issues. The UDL will contain among other things, simulation studies demonstrating compliance and simulation studies predicting plant behaviour during compliance tests and compliance test programme. The plant data should include a verified model of the generator and its control systems in transfer function diagram format.

When National Grid reviews all the endorsed data in the UDL and the accompanying self-certified compliance statements, and if satisfied, it will then consent to synchronisation. This consent is issued as an 'Interim Operational Notification' (ION) by National Grid. This provides notification that National Grid is satisfied with the interim compliance evidence and the Generator may synchronise. Interim Operational Notification will be time limited to cover the commissioning and compliance demonstration period and may include operational constraints. The ION will include a list of any outstanding issues which must be resolved within defined timescales before Final Operational Notification (FON) can be achieved.

Stage 5 – Compliance Testing and Model Validation
Various compliance tests that need to be carried out are listed and described in Chapter 4. Results from these tests should demonstrate not only compliance with the Grid Code and Bilateral Agreement but also the validity of the models submitted for the generator and its control systems. By simulating these compliance tests using the supplied models and comparing the results, the validity of the models could be demonstrated. If the models are shown to be not valid, the generator has to provide updates or modifications to the model until there is good agreement between simulation study results and recorded test results.

At this point there may be another stage "Extension of Interim Operational Notification". It is when the user requests an extension of the Interim Operational Notification (ION) if the commissioning and testing is not completed within the allotted period. The issue of an extension to an ION is subject to the user having made satisfactory progress towards the resolution of the outstanding compliance issues.

Stage 6 – Final Operational Notification
When all outstanding issues listed in the ION are resolved through compliance testing or otherwise, and all data submissions listed in the UDL have been endorsed by the relevant party, the time limitation placed through the ION can be removed and the Generator is issued with a Final Operational Notification (FON).

2.7 Week 24 Data Process

It is a requirement of the Grid Code (PC.4.3) that all Generators submit Standard and Detailed Planning Data on an annual basis. National Grid will contact Generators on calendar week 17 requesting an update of DRC Schedules 1, 2, 4, 5 and 14 which unless otherwise agreed with National Grid, must be provided by the Generator in calendar week 24.

2.8 Lifetime Compliance

The "lifetime compliance process" ensures that plant remains compliant throughout its lifetime. Plant will have been compliant at the time Final Operational Notification (FON) was issued but gradual degradation or replacement can result in a change of status.

After the issue of a FON National Grid will continue to monitor the plant performance and will discuss any concerns with the Generator as part of a normal and ongoing liaison process. This monitoring is particularly focussed, but not exclusively, on performance during frequency incidents and system fault events. In addition the Generators should inform National Grid if the Users system is about to become, or as soon as existing plant becomes non compliant through gradual degradation, or because the User plans to replace or enhance existing plant. National Grid should be informed even if the modification or new plant will be Grid Code compliant. For example if a control system is replaced by a better one, it might fulfil all Grid Code requirements but the model previously submitted would have become invalid and therefore not fit for simulation studies.

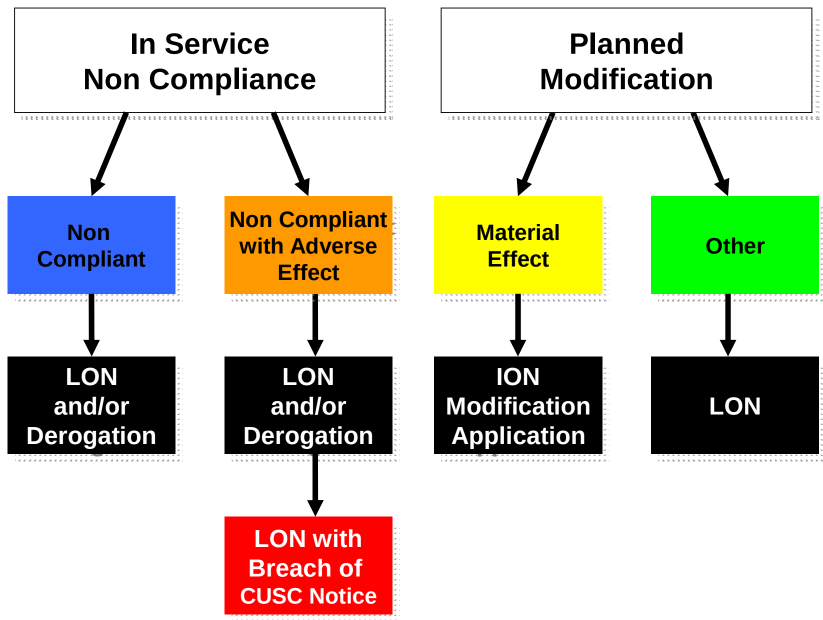


Figure 2.8 – Plant status whilst re-establishing compliance

The status of the plant, in terms of "Operational Notification" from National Grid, whilst the User re-establishes compliance is shown in figure 2.8 and is dependant upon a number of factors, as shown by the diagram and described in the following text.

2.8.1 In Service Non Compliance

The life time compliance process will be triggered, either as a result of an issue arising from National Grids monitoring or as a result of User notifying National Grid of a non compliance. In notifying National Grid of a non compliance as soon as it arises, the generator should include details indicating the nature of the problem, any restriction arising from it and provide an indication as to when it will be rectified.

Figure 2.8.1 below, details the interactions, timescales and resulting outcome (i.e. notification, issue of Limited Operational Notification and referral to OFGEM for a Time Limited Derogation), which are largely dependant on the significance of the non-compliance and the length of time the non compliance is predicted to or actually lasts for.

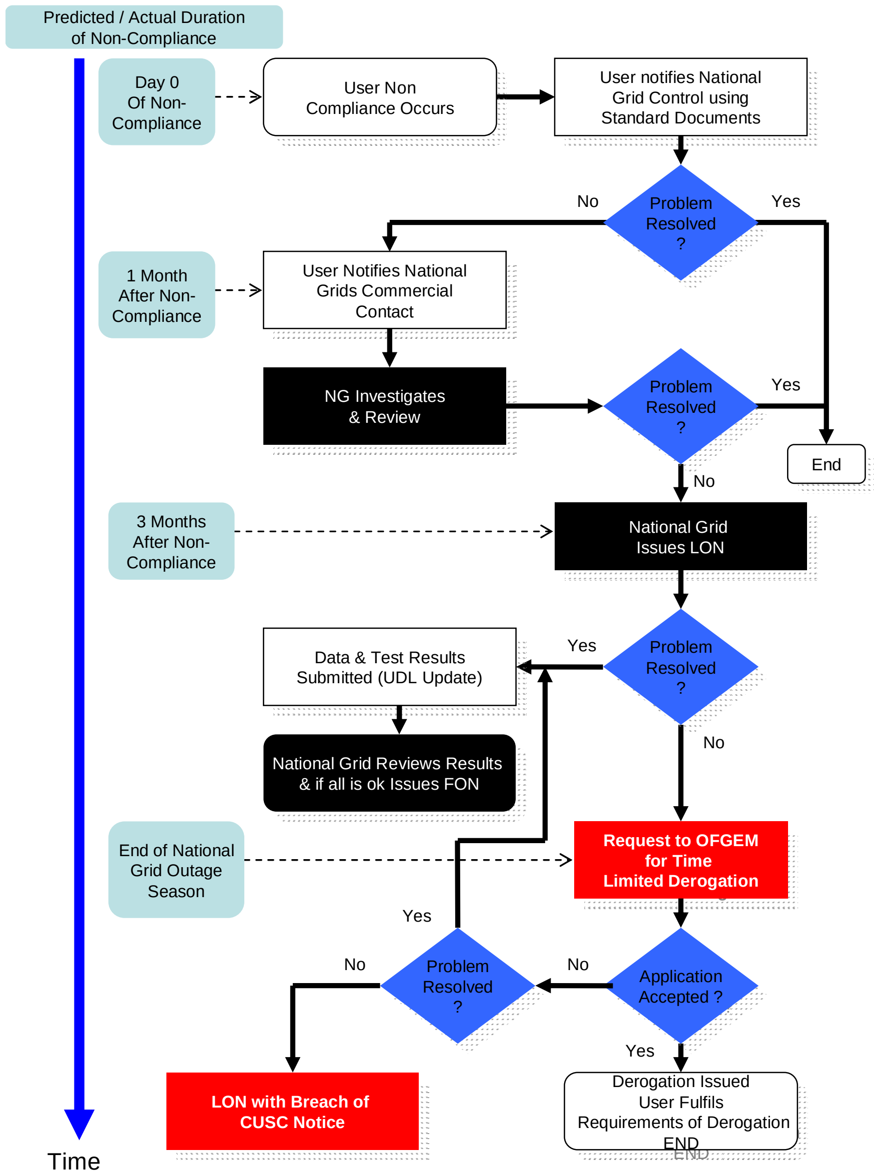


Figure 2.8.1 – Non Compliance Duration and Resolution Outcomes

Notes:

1. The Limited Operational Notification, if issued, will include a schedule of outstanding compliance issues together with timescales for their resolution. Generator Dynamic Performance within National Grid will monitor the situation and identify and notify the User of the tests and studies necessary to confirm that compliance with the Grid Code and Bilateral Agreement has been re-established. Regarding costs arising from non-compliance aspects, the principle that the party who has caused it pays will apply.
2. If the User claims the non-compliance is absolute and cannot be rectified economically the User and National Grid will be required to request the corresponding lifetime derogation. OFGEM may issue a derogation including terms and conditions. Alternatively OFGEM may turn down the request. Requests to OFGEM for derogation can only be made by parties holding a Licence and only for Grid Code related issues.
3. Non compliances which are fixed and then reoccur more than once (i.e. are not fixed in an enduring manner) will on subsequent reoccurrences result in the initial stages of

Figure 2.8.1 being bypassed. Ultimately this will lead to a request for Derogation being initiated.

4. Non Compliance with the Bilateral Agreement but compliance with the Grid Code will not result in requests for derogation but other parts of the procedure will still apply.
5. National Grid will specify the studies and testing required to prove compliance. National Grid will monitor progress of the compliance process and review the evidence. The User remains responsible for progressing resolution so that it complies with its obligations under the CUSC and Grid Code.
6. User's should provide evidence to National Grid of compliance in the form of an updated User Data Library and should include appropriate test and study results.

2.8.2 In Service Non Compliance – Adverse Effect

Where the non compliance does have an adverse effect on National Grid or adversely affects other Users of the system, the User will be notified in writing as soon as possible seeking confirmation that the User will take steps to restore compliance on an urgent basis. Failure to restore compliance may, lead to notification of default and de-energisation in accordance with National Grids rights under the CUSC.

2.8.3 Planned Modification

The User is required to notify National Grid of changes to plant and control systems which result in or have the potential for changing operational characteristics (including the submitted data and models). In addition a new model for the modified or new plant should be submitted to National Grid. These two actions have to be carried out as early as possible so that National Grid can evaluate whether the modified plant will be compliant and will not adversely affect the transmission system or other User's plant.

A Limited Operational Notification (LON) will be issued if there is no Material Effect (as defined in the CUSC) as a result of the changes or an Interim Operational Notification (ION) if there is a Material Effect. The plant will be tested for compliance, where National Grid considers it necessary and assuming the tests indicate that the modified plant is compliant, a Final Operational Notification will be issued.

In situations where some plant/equipment is replaced with newer variants, which are required to and are capable of meeting the latest Grid Code requirements, but the overall performance remains limited to some previously agreed level by other plant not being replaced: National Grid will take a pragmatic view to the level of performance which needs to be achieved and demonstrated. The extent of the design review, studies, testing and the model updating required will be defined on a case by case basis, selecting appropriate parts from this document.

3 SIMULATION STUDIES

Site tests and Simulation Studies are required to provide evidence that the Generators plant and apparatus comply with the provisions of the Grid Code. Site tests are described in the following Section 4. This section describes the simulations studies carried out before the site tests.

In general Simulation Studies are required where:

a) It is impractical to demonstrate capability through testing as the effects on other system users would be unacceptable.
b) It is necessary to predict the synchronous generator behaviour before tests are carried out on the generator.

The following sections outline simulation studies that are required to verify compliance with Grid Code requirements. The simulations must be based on the models supplied to National Grid in accordance with Grid Code Planning Code Appendix section 5.3.2 (PC.A.5.3.2).

The simulations identified here are indicative of the evidence required and will suffice for the majority of Bilateral Agreements and the Grid Code. However if the simulations described here are at variance to the requirements of the Bilateral Agreement / Grid Code, then the Bilateral Agreement / Grid Code will take precedence and the Generator should contact National Grid to agree an alternative simulation program and success criteria.

The Generator is required to provide National Grid and the Transmission Owner (for sites in Scotland) with a model of their Generating Unit as detailed in PC.A.5.3.2 (a to f) of the Grid Code. The model data is to be provided as Laplace transfer functions in a block diagram format. Control systems with a number of discrete states or logic elements may be provided in flow chart format if a block diagram format does not provide a suitable representation.

The model structure and complexity must be suitable for National Grid to integrate into their power system analysis software (currently DigSilent). In cases where the model's functionality cannot be correctly or satisfactorily represented within National Grid's power system analysis software, the Generator may be required to liaise with National Grid to determine appropriate simplifications or changes in representation to produce an appropriate model.

All model parameters must be identified along with units and site-specific values. A brief description of the model should ideally be provided as ultimately this will save time and money for both parties.

The model representation provided should ideally be implemented on a power system analysis software package of the Generator's choosing, as it is otherwise highly unlikely to produce valid results when compared with the test results from the real equipment. In the event the model does not produce the correct output, the data submission will considered incorrect and not contractually compliant. National Grid will confirm the model accuracy.

For Synchronous generators in Scotland the model also needs to be suitable for integration into the power system analysis software used by the relevant Transmission Owner (SPT or SHETL). Support may be required from the Generator to implement and if necessary modify the model representation for use on the Transmission Owner's power system analysis software (ordinarily this will not be the case if the model has already been satisfactorily implemented by National Grid).

3.1 STUDY 1 - Steady State Reactive Capability across the Voltage Range

National Grid Compliance Study	
Title of Study: Steady State reactive Capability	Study Number: 1
User Procedure Reference:	
Description & Purpose of Study: Grid Code CC.6.3.4 requires that the reactive power capability requirements of CC.6.3.2 must be fully available within the voltage range ±5% at 400kV, 275kV, 132kV and lower voltages. It means that there should be sufficient taps on the Generator step-up Transformer to pass through 0.85 lagging to 0.95 leading reactive power at full load active power even with ±5% variation in voltage at the Grid Entry Point. Load Flow type Simulation Studies are required to demonstrate that reactive capability can be delivered over this voltage range. The studies should be performed with the generator terminal volts set to 1pu. **Study 1.1** Load flow study to demonstrate the capability of the synchronous generator to provide maximum lagging reactive power (0.85 pf) at Rated MW when the Grid Entry Point voltage of +5%. **Study 1.2** Load flow study to demonstrate the capability of the synchronous generator to provide maximum leading reactive power (0.95 pf) at Rated MW when the Grid Entry Point voltage of -5%.	

3.2 STUDY 2 – Power System Stabiliser (PSS) Settings

National Grid Compliance Study	
Title of Study: Power System Stabiliser (PSS) Settings	Study Number: 2
User Procedure Reference:	

Description & Purpose of Study:
National Grid requires verification of the chosen PSS settings to provide additional damping of power oscillations in the frequency band 0.2 to 3Hz and thereby provide enhanced response to voltage steps. Grid Code CC.A.6.2.5.6 specifies the following simulation studies for that purpose.

The studies required are as follows:

Study 2.1 Gain and phase Bode diagrams for the open loop frequency domain response of the Generating Unit excitation with and without the PSS, with the synchronous generator operating at maximum leading conditions with the fault level at the HV connection point at minimum. These studies should be in a format that illustrates the phase contribution of the PSS and the gain and phase margin of the excitation system with the PSS.

Study 2.2 On load time series simulations of the response of the excitation system with and without the PSS to 2% and 10% steps in the AVR Voltage Reference Point with the synchronous generator operating at maximum leading conditions and the fault level at the Supergrid HV connection point at minimum.

If the synchronous generator is embedded this study has to be carried out with minimum fault level at the nearest 275kV or 400kV Supergrid busbar. However the network configuration between the Supergrid busbar and the HV side of the Generator Step-up Transformer could be different at times. If it is so, the host Distribution Network Operator should be consulted and the network configuration presenting maximum impedance between the Supergrid busbar and the HV side of the Generator Step-up Transformer should be used.

Study 2.3 Time series simulation of a 100ms solid three phase fault on the HV side of the Generating Unit Transformer with the synchronous generator, with and without PSS, initially operating at Rated Capacity, 1pu volts and at maximum leading conditions (i.e. at or close to UEL) and the fault level at the HV connection point at minimum.

If the synchronous generator is embedded, the fault that the generator has to withstand is not at the HV side of the Generator Unit transformer but at the nearest 275kV or 400kV busbar. The representation of the network between the embedded generator and the Supergrid busbar should be as in Study 2.2

3.3 STUDY 3 – Load Rejection

National Grid Compliance Study	
Title of Study: Unit Load Rejection Capability	Study Number: 3
User Procedure Reference:	

Description & Purpose of Study:

The load rejection capability of a Generating Unit/CCGT Module is critical for System performance under islanding and system split conditions. The unit under these conditions, as indicated in CC.6.3.7 (c) (i) & BC.3.7, must be able to control system frequency below 52Hz unless this causes the Generating Unit to operate below its Designed Minimum Operating Level (DMOL).

Users should confirm the speed control performance of the plant under an instantaneous load reduction from full load, through simulation. The model should be validated by simulating the 0.9Hz injection test described in section F.2.

The simulation should comprise of a generator connected to the UK system with a local load. The local load simulation is additional to the auxiliary load of the power station and represents a small portion of the system to the generator is attached. The generator will be exporting Rated Capacity (RC), some of which will be supplying the local load, whilst the remainder will be supplying the rest of the UK system. The generator will then be islanded by the opening of a breaker, which is not the generator circuit breaker (the governor should therefore, not receive any signals that the breaker has opened other than the reduction in load and subsequent increase in speed).

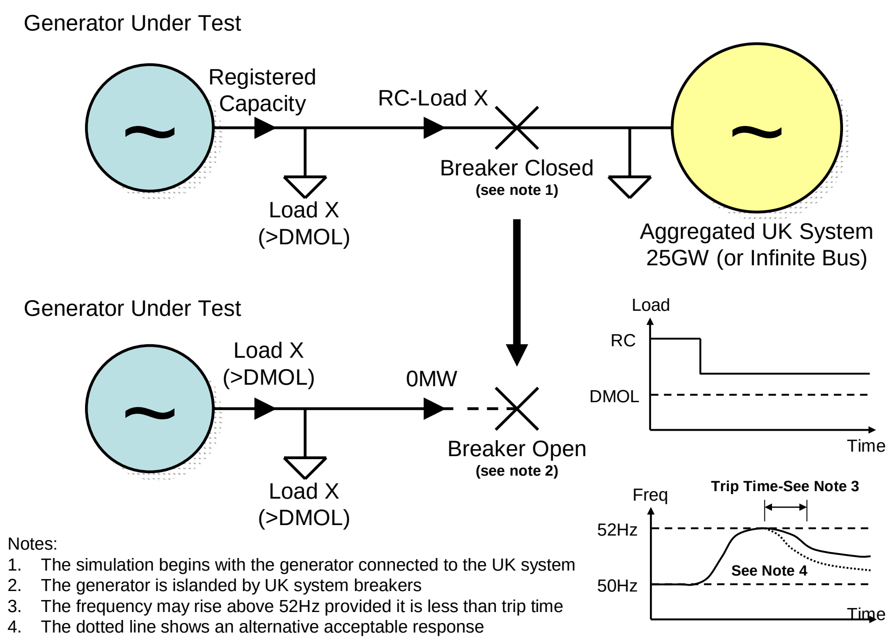


Figure 3.3 – Load Rejection Study

The study should establish the minimum value of the local load (Load X in the diagram) such that the governor can control the frequency to a maximum of 52Hz. The speed may exceed 52Hz transiently provided that the over speed level and duration does not cause the plant to trip.

Studies should be performed for both control modes, Frequency Sensitive Mode (FSM) and Limited Frequency Sensitive Mode (LFSM). This should be achieved with a local load (Load X) of DMOL, however if this can not be achieved then the Load should be set as low as possible such that the machine would not trip in practice.

The study results should indicate MW (Active power), and Nt (Turbine speed). They should also include the over-speed and acceleration protection (alarm & trip) settings.

4 COMPLIANCE TESTING

The tests identified here provide indicative evidence that the requirements of the Grid Code and a typical Bilateral Agreement have been met. However if the test requirements described here are at variance with the Bilateral Agreement then the Bilateral Agreement requirements will take precedence. In this case the Generator should contact National Grid to discuss and agree an alternative test program and success criteria.

The tests are carried out by the Generator, or by their agent, and not by National Grid. For each test to be carried out the description and purpose of the test to be carried out, results required, the relevant Grid Code clause(s) and criteria of assessment are given in the following sections.

The Generator is responsible for providing suitable digital monitoring equipment to record all relevant test signals needed to verify the synchronous generator performance. Minimum sampling rate for recording is 100Hz for excitation control tests and 10Hz for frequency control tests.

National Grid will witness some of the tests and will record data where appropriate. The Generator is responsible for providing the signals in the form of dc voltages within the range -10V to +10V.

4.1 Excitation System Open Circuit Step Response Tests

<table>
<tr><td colspan="2">National Grid Compliance Testing / Monitoring</td></tr>
<tr><td>Title of Test: Excitation System Open Circuit Step Response Test</td><td>Test Number: 1</td></tr>
<tr><td colspan="2">User Procedure Reference:</td></tr>
<tr><td colspan="2">Description & Purpose of Test:
This test will be carried out by the User to assess the small signal performance of the excitation system with the generator operating at no load, at rated terminal voltage and speed.

The test will be carried out by a small step injection into the AVR reference. The magnitude of the step injection will be 5%.

The test should be carried out prior to synchronisation, and settings and results sent to National Grid within 2 days of the test taking place.

Witnessed by National Grid: No</td></tr>
<tr><td colspan="2">Results Required:
Vt - Generator terminal voltage
Vf - Generator field voltage
If - Generator field current
Step injection signal

Results should be legible, identifiable by labelling, and should have appropriate scaling.</td></tr>
<tr><td colspan="2">Test Assessment:
The test results will be assessed against the small signal open circuit excitation system performance specified in Grid Code Connection Conditions Appendix 6.

Criteria of Assessment:
Rise Time, Overshoot, Settling Time, Damping Factor, Nominal Response
(DRC Schedule 1).</td></tr>
</table>

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

4.2 Open & Short Circuit Saturation Characteristics

National Grid Compliance Testing / Monitoring	
Title of Test: Open & Short Circuit Saturation Curves	Test Number: 2
User Procedure Reference:	
Description & Purpose of Test: This test may be carried out by the User to verify the generator field current saturation characteristics. The test should normally be carried out prior to synchronisation, and results sent to National Grid as soon as possible afterwards. Manufacturer type-test results may be used where appropriate. **Witnessed by National Grid:** No	
Results Required: Graphical and tabular representations of per unit Terminal Voltage versus per unit Field Current on Open Circuit. Results should be legible, identifiable by labelling, and should have appropriate per unit scaling.	
Test Assessment: The test results will be used to verify the design value of the short circuit ratio (SCR), where $SCR = \frac{\text{Open Circuit Field Current to obtain 1 pu Terminal Voltage}}{\text{Short Circuit Field Current to obtain 1 pu Terminal Current}}$ CC.6.3.2 of the Grid Code states that generating units should have an SCR of not less than 0.5	

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

4.3 Excitation System On-Load Tests

National Grid Compliance Testing / Monitoring	
Title of Test: Excitation System On Load Tests	Test Number: 3
User Procedure Reference:	

Description & Purpose of Test:

The on load tests are required to evaluate both the steady-state and dynamic stability of the excitation system. For systems which do not employ PSS, this will normally be through small signal step injection into the AVR voltage reference only.

Where a power system stabiliser (PSS) has been specified, tests will also be required to demonstrate that the control system is capable of meeting Bilateral Agreement requirements for power oscillations damping. PSS settings will be required to be verified and agreed by small signal step injection for time domain analysis. In addition, a bandwidth-limited (200 mHz - 3 Hz) random noise injection will be required for spectrum analysis. Both step injection and random noise injection will be carried out with and without the PSS to demonstrate damping. The PSS gain should be continuously controllable (i.e. not discrete components) during testing.

The PSS gain margin should be tested by increasing the PSS gain gradually by threefold and observing the generator steady state MW output. If there are oscillations in the MW more than 5% of the original value of MW before the threefold PSS gain increase, then the PSS gain should be reduced until adequate gain margin is established.

If the generator is part of a pump storage scheme then the step tests should be carried out, with and without the PSS, in the pumping mode as well.

Prior to synchronising the User should provide National Grid with a procedure for on load excitation tests, along with necessary supporting information. This should contain:-

- Design study and simulation results (Studies 2.1 and 2.2 described in Section 3.2) .
- Proposed on-load step injection size (normally 1-2%).
- Anticipated MW and MVAr changes.
- Excitation system block diagram and settings, showing PSS control and settings where applicable (As provided in Grid Code submissions (DRC Schedule 1)).

Based on the information provided in the report, National Grid will meet with the User to discuss and agree the PSS settings - where applicable.

National Grid will not permit PSS commissioning unless the methodologies and study results used in any PSS settings proposal and optimisation have been provided to National Grid in an acceptable time scale. Ideally, this should be provided along with the procedure. In any case, the provisions of BC2.11.2 will apply.

The PSS is required to remain switched in while the UEL is active. However under these conditions, the excitation should not be taken below the UEL limit by the PSS signal.

Where a PSS has been specified, the User should provide a suitable band limited (200 mHz - 3 Hz) noise source to facilitate noise injection testing.

Where a PSS has not been specified in the Bilateral Agreement but has been fitted and not been disabled, the whole process described above still has to be carried out.

The tests will normally be carried out to an agreed procedure and at an agreed time prior to the unit reliability / acceptance period. A generic procedure is shown in Appendix C.2. **Witnessed by National Grid:** Yes
Results Required: MW - Active power at generator terminals MVAr - Reactive power at generator terminals Vt - Generator terminal voltage Vf - Generator field voltage PSS Output Results should be legible, identifiable by labelling, and should have appropriate scaling.
Test Assessment: The test results will be assessed against: • Performance specifications in Appendix F5 (F4 for embedded generating plant) of the Bilateral Agreement between National Grid and the User. • CC.A.6.2.4, CC.A.6.2.5 and CC.A.6.2.6 of the Grid Code **Criteria of Assessment:** • Both small signal and large signal performance criteria will be used in the evaluation of the Excitation system, using recognised performance indices. • Time Domain: step response voltage regulation (rise time and settling time according to CC A.6.2.4.1). • Frequency Domain: damping of frequencies in the band 200mHz - 3Hz, gain margin, phase margin.

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

4.4 Under Excitation Limiter Performance

National Grid Compliance Testing / Monitoring	
Title of Test: Excitation System Under Excitation Limiters	Test Number: 4
User Procedure Reference:	

Description & Purpose of Test:

This test will be carried out by the User to verify the performance of the under excitation limiter (UEL).

The test should be carried out at more than one load point to confirm the setting of the limiter on the generator performance capability chart. AVR and limiter response tests will normally be carried out at low load points prior to testing at, or near, full load.

The User must provide a procedure to National Grid describing how the tests will be carried out. This procedure should include the following details:

Generator operating points (MW, MVAr).
Proposed on-load step injection size which must be 2% (CCA.6.2.7.2).
Generator transformer tapping requirements.
Anticipated MW / MVAr changes.
Excitation System block diagram, showing limiter control *.
PSS status.
Generator performance chart indicating automatic and manual limits *.
* As provided in Grid Code submissions (DRC Schedule 1).

The tests, with PSS in service, will normally be carried out to an agreed procedure and at an agreed time prior to the unit reliability / acceptance period. A generic procedure is shown in Appendix C.3.

The Under Excitation Limiter must be active when the AVR is in both auto and manual modes, the User must notify National Grid if this is not the case.

Witnessed by National Grid: Normally only tests at full load conditions will be witnessed.

Results Required:

MW - Active power at generator terminals
MVAr - Reactive power at generator terminals
Vt - Generator terminal voltage
Vf - Generator field voltage

Results should be legible, identifiable by labelling, and should have appropriate scaling.

Test Assessment:

The test results will be assessed against:
• CC.6.3.8, of the Grid Code, which requires automatic excitation control without instability over the entire operating range of the generating unit.
• CC.A.6.2.7.2
• Performance specifications in Appendix F5 (F4 for embedded generating plant) of the Bilateral Agreement between National Grid and the User.

Criteria of Assessment:

• Correct operation of the UEL for either step injection or generator transformer tap change.
• Amount of overshoot following a step injection at UEL less than 4% and the time of recovery to the UEL setting less than 5 seconds (CC.A.6.2.7.2)
• Damped control of generator terminal voltage, MW and MVAr.

4.5 Over Excitation Limiter Performance

<table>
<tr><td colspan="2">National Grid Compliance Testing / Monitoring</td></tr>
<tr><td>Title of Test: Over Excitation Limiter Tests</td><td>Test Number: 5</td></tr>
<tr><td colspan="2">User Procedure Reference:</td></tr>
<tr><td colspan="2">Description & Purpose of Test:
This test will be carried out by the User to verify the performance of the over excitation limiter (OEL).(CC.A.6.2.8.2)

The User should provide a procedure to National Grid describing how the tests will be carried out. This procedure should include the following details:

Generator operating points (MW, MVAr).
Proposed on-load step injection size (normally 2%-10%).
Generator transformer tapping requirements.
Anticipated MW / MVAr changes
Excitation System block diagram, showing limiter control *.
PSS status.
* As provided in Grid Code submissions (DRC Schedule 1).

The tests will normally be carried out to an agreed procedure and at an agreed time prior to the unit reliability / acceptance period. A generic procedure is shown in Appendix C.4.

In addition to the test, the User must confirm and provide evidence that the OEL has been set as high as design limit of the machine allows. (CC.A.6.2.8.1). If the test can not be carried out at this set value due to operational constraints then the OEL setting could be reduced for testing purposes. It should then be returned to the design setting following the test.

Witnessed by National Grid: Yes</td></tr>
<tr><td colspan="2">Results Required:
MW – Active power at generator terminals
MVAr – Reactive power at generator terminals
Vt – Generator terminal voltage
Vf – Generator field voltage

Results should be legible, identifiable by labelling, and should have appropriate scaling.</td></tr>
<tr><td colspan="2">Test Assessment:
The test results will be assessed against:
• CC.A.6.2.8.2
• Performance specifications in Appendix F5 (F4 for embedded generating plant) of the Bilateral Agreement between National Grid and the User.
Criteria of Assessment:
• The OEL operation has an appropriate time delay to avoid protection tripping.
• The OEL setting is as close as possible to the machine design limit.
• The OEL action does not produce any MVAr or MW oscillations</td></tr>
</table>

4.6 Reactive Capability

<table>
<tr><td colspan="2">National Grid Compliance Testing / Monitoring</td></tr>
<tr><td>Title of Test: Reactive Capability</td><td>Test Number: 6</td></tr>
<tr><td colspan="2">User Procedure Reference:</td></tr>
<tr><td colspan="2">Description & Purpose of Test:
National Grid will require a demonstration of the leading and lagging reactive power capability on each generating unit to demonstrate compliance with CC.6.3.2 and CC.6.3.4. This requirement is to have the capability to achieve 0.85 lagging and 0.95 leading power factors at the generator terminals, while supplying rated active power for all normal transmission system voltage conditions.

This will normally be achieved by operation of the generating unit at the required power factor for an agreed duration, to verify the generator performance chart.

This test will be co-ordinated by National Grid Network Operations (with details given in a National Grid note entitled- New Generating Stations MVAr Capability Tests) at an agreed time during the reliability / acceptance period of the commissioning process. The test will be to the instruction of the National Grid Control Engineer and should be monitored and recorded at both the National Grid Control Centre and by the User. The test duration will be agreed between the User and National Grid Network Operations.

Witnessed by National Grid: Not normally but National Grid may choose to witness the test.</td></tr>
<tr><td colspan="2">Results Required:
MW - Active power at generator terminals
MVAr - Reactive power at generator terminals
HV - System (HV) voltage
LV – System (LV) voltage
Generator transformer tap setting
Ambient conditions (temperature and pressure)

Results should be legible, identifiable by labelling, and should have appropriate per unit scaling.</td></tr>
<tr><td colspan="2">Test Assessment:
The test results will be assessed against:
• CC.6.3.2, CC.6.3.4 and OC.5.5.1
Criteria of Assessment:
• Confirmation of the full reactive capability of the generating unit, from 0.85 lagging to 0.95 leading at rated MW</td></tr>
</table>

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

4.7 Governor and Load Controller Response Performance

National Grid Compliance Testing / Monitoring	
Title of Test: Governor Response	Test Number: 7
User Procedure Reference:	
Description & Purpose of Test: The tests, for compliance purposes, should; demonstrate the capability of each generating unit or CCGT module to continuously modulate active power to contribute to frequency control; validate the governor model submitted to National Grid, assess dead-band, incremental droop, steady-state/dynamic stability of the governor and demonstrate the robustness of the control system. At the same time, the tests will also be used to populate the Mandatory Services Agreement frequency response matrices, for frequency services and response capability assessment. For stations with a completion date after 1 January 2001 the established response capability will be checked to ensure its compliance with the minimum frequency response requirements set out in CC.6.3.7 (e). These requirements are applicable to all plant types (Nuclear, Supercritical Steam etc.). A brief description is given in Appendix D. Simulated frequency deviation signals must be injected simultaneously at both speed governor and load controller references. For Combined Cycle Gas Turbine modules, simultaneous injection into all gas turbines, steam turbine governors and module controllers is required. The correct co-ordination of the governor/load controller is given in Appendix E. Prior to witnessing a governor test, National Grid will request the User to conduct preliminary tests and send the results to National Grid GDP for assessment. These tests should be completed at least two weeks prior to the main governor response test. Details of preliminary and main test procedures are included in Appendix F. **Witnessed by National Grid:** Yes	
Results Required: Although National Grid generally provides digital monitoring equipment to record the agreed signals during the National Grid witnessed governor response tests, the User will also be required to provide their own digital monitoring and recording equipment to record the signals for back up purposes. Generators are responsible for providing the signals to National Grid (voltage range ±10V) for data recording (minimum sampling rate ≥ 10Hz). Typical signal schedules for CCGT, thermal and hydro electric plant are included in Appendix D.4. This may be modified to suit specific sites following consultation with National Grid. **Test Assessment** The test results will be assessed against: • CC.6.3.6, CC.6.3.7, CC.8.1 • BC3.5, BC3.6, BC3.7, BC.3.7.1 (c) and BC.3.7.2	
Criteria of Assessment • Fast acting proportional control delivered linearly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** change as illustrated by the Plant Response in Figure CC.A.3.2. If there is an initial inherent delay in the increase of **Active Power** output following a **Frequency** fall, this must be minimised as far as is reasonably practicable and in any event such a delay should be no longer than two seconds unless in NGET's reasonable opinion a longer delay is unavoidable.	

- Unit / Module droop in the range of 3 - 5%.
- Continuous frequency modulation capability and stable operation from Designed Minimum Operating Level to Maximum Export Limit (MEL).
- Capable of withstanding frequency disturbances without tripping (CC.6.3.7).
- Confirmation of minimum frequency response will be accepted if the responses obtained are equal to or exceed the minimum requirements specified in Appendix CC.A.3 of the Grid Code. i.e. Primary, Secondary & High Frequency Response capability of the module >10% on unit/module Registered Capacity.
- Results verify the Mandatory Ancillary Services Agreement matrices to the satisfaction of National Grid.
- In LFSM mode the plant should begin to reduce it output, at least by the specified minimum or above, when the frequency goes above 50.4 Hz (BC.3.7.2)
- In FSM mode the plant should continue to provide HF response, at least by the specified minimum or above, when the frequency goes above 50.5 Hz (BC.3.7.1 (c))

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements

4.8 Compliance with CC.6.3.3

National Grid Compliance Testing / Monitoring	
Title of Test: Compliance with CC.6.3.3, BC.3.7.1(c) and BC.3.7.2	Test Number: 9
User Procedure Reference:	

Description & Purpose of Test:

CC.6.3.3 defines the capability of a plant irrespective of its operating mode (i.e. Frequency Sensitive or Limited Frequency Sensitive Mode). An interpretation of the requirement is shown in Figure 1 below. Generators under frequency disturbance conditions are required to remain in the acceptable zone.

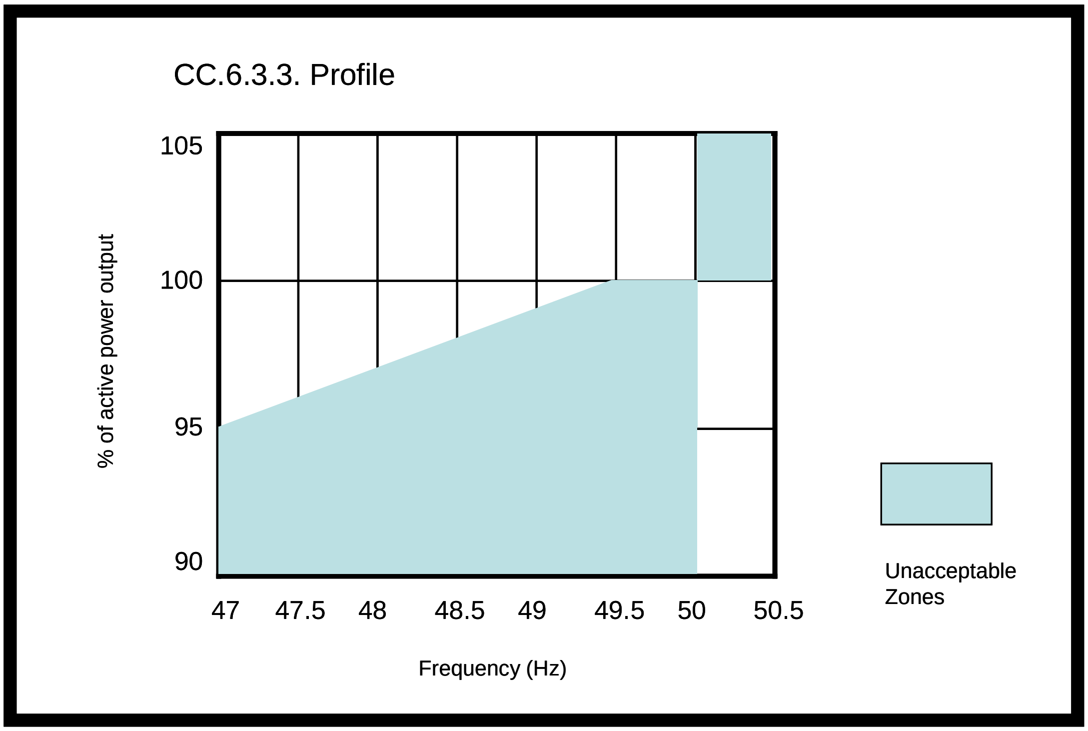


Figure 1

For Limited Frequency Sensitive operation, as specified in BC.3.5.2 and BC.3.7.2, the output of the generator must achieve the CC.6.3.3 requirement up to 50.4 Hz above which a minimum power reduction rate of 2% per 0.1 Hz must be achieved.

National Grid will require the User to demonstrate generator unit performance in accordance with the above requirements. This should comprise of the following four stages:-

Pre-commissioning:- The User will need to supply National Grid with information relating to the plants MW output, speed and ambient temperature performance characteristics and the relevant design methodology employed within the control system, to ensure the necessary correction to the plant output to meet the requirements.

Functionality Testing:- Following installation of the control system, the User will propose and agree a test procedure with National Grid, which will demonstrate how the plant output power

responds to changes in system frequency and ambient conditions (e.g. by frequency and temperature injection methods). This functionality test should include the frequency injection test shown in Appendix F **Validation: -** On satisfactory conclusion of the above, National Grid would consider the Users plant to be compliant. As part of the life time compliance, National Grid will continue to monitor the plants performance and will discuss any concerns with the User as part of the normal and ongoing liaison process. **Witnessed by National Grid:** Yes for functionality testing
Results Required: MW **-** Active power at generator terminals Fs **-** System frequency Tamb- Ambient temperature Control system parameters as agreed with National Grid National Grid will inform the User which additional control system parameters should be monitored. The User should inform National Grid if any load limiter control is additionally employed. Signals should be sampled no slower than 10Hz. Results should be provided to National Grid in electronic form, in a format suitable for use in spreadsheets.
Test Assessment: The test results will be assessed against: • CC.6.3.3 **Criteria of Assessment:** • Continuous compliance with MW output tolerance of ± 0.2 % (OC 5.5.2.2 (b)). There should be no time limitation and no dead-band operation.

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

5 MODEL VALIDATION

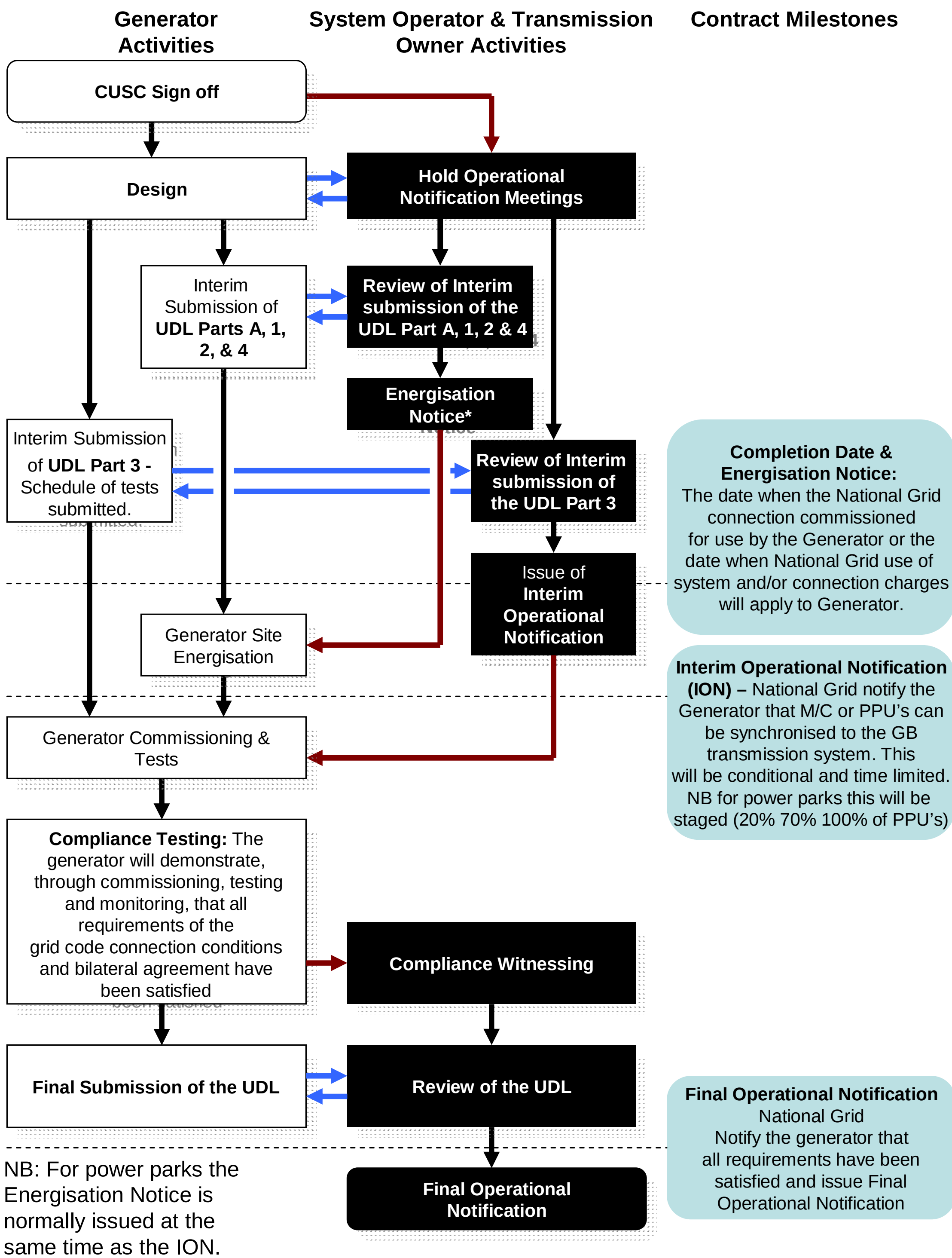
The results recorded during the above tests may be used to validate the model of the excitation control system and the frequency control system.

The tests above may have proved that the generator and its control systems are compliant but the recorded behaviour tests may be different from the behaviour predicted by the simulation studies using the provided models. The differences may be due to the following reasons.

- The simulation conditions are different from the test conditions
- The model supplied may be not accurate.

Simulation of the test under the test conditions should be carried out and the simulation results should be then compared with the test results. If the results are identical or matched very well then the submitted model has been validated and accepted as the accurate model of the plant. If the results are different then the Generator, or the Generators agent, i.e. consultant or equipment manufacturer, should resubmit a modified model. This process will be repeated until there is close agreement with the test results and simulation results.

APPENDIX A COMPLIANCE PROCESS



APPENDIX B USER DATA LIBRARY (UDL)

B.1 Outline Structure

The outline structure of the UDL is given below. It is important users submit data correctly under the main five subsections as this will ensure it is routed correctly to the relevant department within National Grid and to the relevant TO / DNO.

User Data Library - Outline Structure		Lead Role	Indicative Data Sharing SO	TO
Part A: Commercial & Legal				
A.1	Signed Legal Agreements	SO	#	
A.2	Commissioning & Test Programmes	SO	#	#
	Connection Site Commissioning & Test Programme	SO	#	#
	Generating Unit Commissioning Program	SO	#	#
	Generator Control Test Procedures and Programme	SO	#	#
A.3	Statements of Readiness	SO	#	#
A.4	TOGA Registration Details	SO	#	
A.5	Mandatory Services Agreement	SO	#	
A.6	Codes for Balancing Market Units	SO	#	
A.7	BMU Registration	SO	#	
A.8	Balancing Mechanism Process	SO	#	
A.9	Ancillary Services Monitoring	SO	#	
A.10	User Self Certification of Compliance	SO	#	
A.11	Compliance Statement	SO	#	
Part 1: Safety & System Operation				
1.1	Interface Agreements	TO	#	#
1.2	Safety Rules	TO	#	#
1.3	Local Switching Procedures	TO	#	#
1.4	Earthing	TO	#	#
1.5	Site Responsibility Schedules	TO	#	#
1.6	Operational and Gas Zone Diagrams	TO	#	#
1.7	Site Common Drawings	TO	#	#
1.8	Control Telephony	TO	#	#
1.9	Local Safety Procedures	TO		#
1.10	Safety Co-ordinators	TO		#
1.11	RISSP	TO	#	#
1.12	Telephone Numbers for Joint System Incidents	SO	#	#
1.13	Contact Details (fax, tel, email)	SO	#	#
1.14	Local Joint Restoration Plan (incl. black start if applicable)	SO/TO	#	#
1.15	Maintenance Standards	SO/TO	#	#
Part 2: Connection Technical Data				
2.1	DRC Schedule 5 - Users System Data	TO	#	#
2.1.1	*System Configuration Data*	TO	#	#
	Users System Layout & Single Line Diagram	TO	#	#
	Reactive Compensation	TO	#	#
	Substation Infrastructure	TO	#	#
	Circuit Parameters	TO	#	#
	Transformer Data	TO	#	#
	Switchgear Data	TO	#	#
2.1.2	*Protection Systems*	TO	#	#
	User System protection and settings	TO	#	#
	User System Auto Reclose facilities & settings	TO	#	#

	User System protection and settings	TO	#	#
	Circuit Breaker Fail	TO	#	#
	Generator Transformer protection and settings	TO	#	#
	System Fault Clearance Times	TO	#	#
	Generator protection and settings	SO	#	#
2.1.3	*User System Studies (if required)*	TO	#	#
2.2	Protection Settings Reports	TO	#	#
2.2.1	*Protection Discrimination Review*	TO	#	#
2.2.2	*Protection of Interconnecting Connections*	TO	#	#
2.3	Special Automatic Facilities e.g. intertrip)	TO	#	#
2.4	Operational Metering	TO	#	#
2.5	Tariff Metering	Elexon	#	#
2.6	Operational Communications	SO	#	#
2.6.1	*EDL & EDT*	TO	#	#
2.7	Performance Monitoring	SO	#	#
2.7.1	*Ancillary Services Monitoring*	TO	#	#
2.7.2	*Fault Recorder*	TO	#	#
2.7.3	*Dynamic System Monitor (if required)*	TO	#	#
2.7.4	*Power Quality Monitor (if required)*	TO	#	#
2.8	Power Quality Test Results (if required)	TO	#	#

Part 3: Generator Technical Data

3.1	DRC Schedule 1 - Generating Unit Technical Data	SO	#	#
3.1.1	*Table of Generator Parameters*	SO	#	#
3.1.2	*Controls System Details*	SO	#	#
3.1.3	*Generator / Station Model*	SO	#	#
3.1.4	*Power Quality - Harmonic Assessment Information*	SO	#	#
3.2	DRC Schedule 2 - Generation Planning Data	SO	#	#
3.3	DRC Schedule 4 – Frequency Droop & Response	SO	#	
3.4	DRC Schedule 14 – Fault Infeed Data - Generators	SO	#	#
3.5	Special Generator Protection	SO	#	#
	Pole Slipping Protection	SO	#	#
	Islanding Protection Schemes	SO	#	#
3.6	Compliance Tests & Evidence	SO	#	#
3.6.1	*Reactive Capability*	SO	#	#
3.6.2	*Voltage Control (e.g. Excitation, AVR PSS)*	SO	#	#
3.6.3	*Frequency Response (Governor)*	SO	#	
3.7	Compliance Simulation Studies	SO	#	#
3.7.1	*Model Verification*	SO	#	#
3.7.2	*Reactive Capability & Voltage Range*	SO	#	#
3.7.3	*Voltage Control & Stability (e.g. AVR, PSS)*	SO	#	#
3.8	Site Specific Technical Data & Compliance	SO	#	#
3.8.1	*Special Automatic Features e.g. intertrip*	SO	#	#

Part 4: General DRC Schedules

4.1	DRC Schedule 3 – Large Power Station Outage Information	SO	#	
4.2	DRC Schedule 6 – Users Outage Information	SO	#	
4.3	DRC Schedule 7 – Load Characteristics	SO	#	
4.4	DRC Schedule 8 – BM Unit Data (if applicable)	SO	#	
4.5	DRC Schedule 10 – Demand Profiles	SO	#	
4.6	DRC Schedule 11 – Connection Point Data	SO	#	

B.2 Final User Data Library

Updated the contents of the Interim submission to reflect any changes and add the compliance test results.

- Plant & Apparatus Type Test Results
- Reactive Capability and Voltage Control Test Results
- Frequency Response Test Results

The above structure is indicative, but is a useful convention for Generators to follow. National Grid will inform the Generator where additional supporting information is required.

B.3 Protection Requirements

Under section CC.6.2.2.2 of the Grid Code the Generator must meet a set of minimum protection requirements. As part of the Connection Conditions Compliance Report the Generator should submit a Generator Protection Settings report together with an overall trip logic diagram.

The Generator should provide details of all the protection devices fitted to the Power Station together with settings and time delays, including:

Protection Fitted	Typical Information Required
Under / Over Frequency Protection	Number of stages, trip characteristics, settings and time delays
Under / Over Voltage protection	Number of stages, trip characteristics, settings and time delays
Over Current Protection	Element types, characteristics, settings and time delays
Reverse Power Protection	Number of stages, trip characteristics, settings and time delays
Control Trip Functions	Functional Description, Control Characteristic and trip settings
Islanding Protection (if fitted)*	Type, description, settings and time delays

*An intertripping scheme is recommended. If 'Rate of Change of Frequency' (ROCOF) or 'Vector Shift' trip relays are to be considered, there could be compliance implications which need to be discussed with National Grid at the earliest opportunity. National Grid does not require or desire Generators to fit ROCOF or 'Vector Shift' protection but needs to be consulted on the settings of any such protections in service.

APPENDIX C VOLTAGE CONTROL

C.1 Summary of Grid Code Requirements

The generic requirements for voltage control are set out in the Grid Code Connection Conditions with any site specific variations included in the Bilateral Agreement. This section summarises the key requirements using the generic values included in the Grid Code.

Grid Code CC.6.3.8 (a) requires provision of a continuously acting voltage control to provide constant terminal voltage control without instability over the entire operating range of the synchronous generator. Grid Code CC Appendix 6 specifies the performance requirements of such an excitation control.

Selected Grid Code CC Appendix 6 requirements are summarised below. The User should refer to the Grid Code for the full requirements given in CC Appendix 6:

Requirement

- CC.A.6.2.2 The excitation control should include a PSS as a standard component of new and replacement excitation systems.

Steady State Voltage Control

- CC.A.6.2.3.1 The static zero frequency gain of the excitation control system should be large enough to limit the voltage drop to <0.5% when gradually changing from zero to rated MVA output.

Transient Voltage Control

- CC.A.6.2.4.1 When the generating unit is on open circuit, for a step change from 90% to 100%, the response should be damped oscillations, with time for the first reach of 100% within 0.6 seconds and settling time within 5% of nominal voltage in less than 3 seconds
- CC.A.6.2.4.2 For large voltage disturbances, e.g. 10% step, the AVR should be capable providing its upper or lower limit ceiling voltages within the time specified in the Bilateral Agreement.
- CC.A.6.2.4.4 If a static exciter is employed then it should be capable of attaining negative ceiling voltage specified, maintain free firing when the terminal voltage depress to be between 20-30% of rated voltage, and be capable of attaining positive ceiling voltage upon recovery of the terminal voltage to 80% of the rated value following fault clearance.

Power Oscillations Damping Control

- CC.A.6.2.5.3 The PSS output signal relates only to changes in the supplementary control signal and not the steady state level of the signal.
- CC.A.6.2.5.4 The output signal from the PSS shall be limited to $\pm$10% of the terminal voltage signal at the AVR input.
- CC.A.6.2.5.5 The output signal of the PSS should be bandwidth limited (0-5Hz).

Overall Excitation System

- CC.A.6.2.6.1 The output signal of the overall excitation system should be bandwidth limited (0-5Hz).
- CC.A.6.2.6.2 With the generating operating open circuit at 100% rated voltage, a 2% step in the voltage reference should first reach 102% in less than 0.4 seconds and settle within $\pm$5% of 1.02 pu within 1.6 seconds.
- CC.A.6.2.6.4 The PSS should be demonstrated by test to provide improved damping to the active power output for a 0.2-3Hz bandwidth limited white noise injection in the AVR reference junction.

Under-Excitation Limiter (UEL)

- CC.A.6.2.7.1 The UEL should act to prevent the AVR reducing the generator excitation to a level which would endanger synchronous stability.

- CC.A.6.2.7.2 The action of the UEL should be demonstrated by a step corresponding to a 2% decrease in AVR reference voltage while the generator is operating just off the UEL limit line.
- CC.A.6.2.7.3 There should be a provision to prevent the reduction of the excitation to a level which would endanger synchronous stability when the Excitation Control is under manual control.

Over-Excitation Limiter (OEL)

- CC.A.6.2.8.1 The OEL should be set at the maximum value possible within the design limits. Also if the OEL operates to reduce the excitation following a period of high excitation, then the rate of reduction should not exceed the minimum rate to remain within time dependent over excited operation characteristics of the generator.
- CC.A.6.2.8.2 The action of the OEL should be demonstrated by a step corresponding to a 2%-10% increase in AVR reference voltage while the generator is operating just off the OEL limit line.
- The OEL setting must be set lower than the trip setting and any overshoot must not result in a trip CC.A.6.2.8.2.
- CC.A.6.2.8.3 When the Excitation Control is under manual control, there should be a provision to prevent any restriction of the excitation to a level that is less than necessary to operate within the design limit.

The Bilateral Agreement will include any variations to the requirements in the Grid Code applicable to an individual unit.

The Generator must provide National Grid with a transfer block diagram of the excitation control system and include all associated parameters. This forms part of Schedule 1 of the Data Registration Code and should be included in part 3 of the User Data Library (UDL).

C.2 Power System Stabiliser Testing

National Grid will not permit PSS commissioning until the tuning methodologies and study results used in any PSS settings proposal have been provided to National Grid. A report on the PSS tuning should be provided (Refer Section 3.2) along with the proposed test procedure in the User Data Library (Part 3). Based on the information submitted, National Grid will meet with the generator to discuss and agree the initial PSS settings for commissioning.

The suitability of the tuning of any PSS is checked in both the time and frequency domains. In the time domain testing is by small voltage step changes injected into the AVR voltage reference block. Comparisons are made between performance with and without the power system stabiliser in service.

For analysis in the frequency domain, a bandwidth-limited (200mHz-3Hz) random noise injection should be made to the AVR voltage reference. The generator should provide a suitable band limited (200mHz-3Hz) noise source to facilitate noise injection testing. The random noise injection will be carried out with and without the PSS in service to demonstrate damping. The PSS gain should be continuously controllable (i.e. not discrete components) during testing.

The suitability of the PSS gain will also be assessed by increasing the gain in stages to 3x the proposed setting. This increase is carried out gradually while monitoring the generator for any signs of instability.

The tests will be regarded as supporting compliance if:

- The PSS gives improved damping following a step change in voltage.
- Any oscillations are damped out within 2 cycles
- The PSS gives improved damping of frequencies in the band 300mHz – 2Hz.
- The gain margin is adequate if there is no appreciable instability at 3x proposed gain

The following generic procedure is provided to assist Generators in drawing up their own site specific procedures for the National Grid witnessed PSS Tests.

Step No	Test	Injection	Notes
		Synchronous Generator running rated MW, unity pf, PSS Switched Off	
1 2 3	1	• Record steady state for 10 seconds • Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
4 5 6	2	• Record steady state for 10 seconds • Inject +2% step to AVR Voltage Reference and hold for at least 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
7 8	3	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	
9		• Switch On Power System Stabiliser	
10 11 12	4	• Record steady state for 10 seconds • Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
13 14 15	5	• Record steady state for 10 seconds • Inject +2% step to AVR Voltage Reference and hold for at least 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
16 17	6	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	
18 19	7	• Increase PSS gain at 30second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3 • Return PSS gain to initial setting	
20	8	• Select the governor to FSM • Inject +0.5 Hz step into governor. • Hold until generator MW output is stabilised • Remove step	

C.3 Under Excitation Limiter (UEL) Testing

This test is carried out to establish the setting of the limiter and to verify its correct operation including adequate damping. If the excitation control system includes a PSS, tests should be carried out with PSS switched on.

NB it may prove beneficial to perform an optional test with the PSS off, to understand the interaction between the PSS and limiter.

The UEL action should be initiated by injecting a negative voltage step of -2% into the AVR voltage reference, with the generator initially operating near the UEL limit. The test procedure given below details the step injection method.

When the generator is operating near the UEL limit the stability margin is less than when it is operating at unity power factor. For safety a preliminary set of tests are specified below with the UEL limit moved towards unity power factor line. If the preliminary tests are successful then the UEL limit is moved to its design position and the tests are repeated.

The following generic procedure is provided to assist Generators in drawing up their own site specific procedures for the National Grid witnessed UEL Tests.

Step No	**Test**	**Injection**	**Notes**
		Synchronous generator running MEL at unity power factor. UEL limit temporarily moved close to the operating point of the generator.	
1 2 3	1	• PSS on. • Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
		UEL limit moved to normal position. Synchronous generator running at MEL and at leading MVArs close to UEL limit.	
4 5 6	2	• PSS on. • Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds • Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	

C.4 Over Excitation Limiter (OEL) Testing

OEL test requirements are normally discussed with National Grid prior to testing in order to establish a sensible test procedure, appropriate to the control system design. The following generic procedure is provided to assist Generators in drawing up their own.

National Grid are particularly interested in ensuring the OEL is set as high as possible, whilst ensuring the machine design limits are not breached and that the machine protection will not operate whilst the OEL is active.

The OEL action is typically initiated by injecting a +2 to +10% positive voltage step into the AVR voltage reference. The OEL would normally be set at the maximum value within the design limit for the generator. Excitation at OEL setting is well above excitation at rated MVA. For this reason the test is not typically carried out at the OEL setting. For the test the OEL setting is typically reduced to a level equivalent to the maximum rated MVA position, i.e. rated MVA and maximum lagging MVAr. A positive step is then applied to the AVR Voltage reference or the Generator Step-up Transformer is tapped to take the MVAr output higher. If the OEL is working correctly, the OEL should operate after sufficient time delay to bring back the excitation within limits.

The steady state accuracy of the limit level and any overshoot are of particular interest, as the Generator and National Grid may need to determine the limit level once the setting is restored and ensure that any protection does not operate.

If the OEL has multiple levels to account for heating effects, an explanation of this functionality will be necessary and if appropriate, a description of how this can be tested.

Step No	Test	Injection	Notes
		Synchronous Generator running rated MW and maximum lagging MVAr.	
1		OEL temporarily set close to this operating point. PSS on.	
2 3 4	1	• Inject positive voltage step into AVR voltage reference and hold • Wait till OEL operates after sufficient time delay to bring back the excitation back to the limit. • Remove step returning AVR Voltage Reference to nominal.	
5		OEL restored to its normal operating value. PSS on.	

APPENDIX D GENERAL INFORMATION ON GOVERNOR RESPONSE ISSUES

Sections 4.7 and 4.8 of this document describes the requirements on Users to demonstrate that the governor and unit load controller satisfy the requirements of the Grid Code. Past experience has demonstrated that a number of issues can arise prior to and during testing. For this reason, detailed information relating to the governor/load controller is presented in this Appendix D. This includes information on minimum frequency response requirements, compliance testing and test recording arrangements. Testing on dual fuelled plant is also discussed.

Appendix E defines the functionality requirements for the governor/load controller. This information is essential for the correct co-ordination of the plant control to meet the Grid Code requirements.

Appendix F provides details of the tests required for the preliminary and main governor response tests.

D.1 Minimum Frequency Response Requirements

The minimum frequency response requirement profile as defined in Appendix 3 of the Connection Conditions of the Grid Code is shown diagrammatically in Figure D1. The capability profile specifies the minimum required levels of Primary Response, Secondary Response and High Frequency Response throughout the normal plant operating range. The interpretation of these frequency response capabilities are illustrated diagrammatically in Figures D2 & D3. This requirement only applies to stations that have a completion date after 1 January 2001.

The upper limit of the operating range is the Registered Capacity (RC) of the Generating Unit or CCGT Module. The Minimum Generation (MG) level may be less than, but must not be more than, 65% RC. Each Generating Unit and/or CCGT Module must be capable of operating satisfactorily down to the Designed Minimum Operating Level (DMOL) as dictated by system operating conditions, although it will not be instructed below its MG level. The DMOL must not be more than 55% RC. Each Generating Unit and/or CCGT Module must be capable of providing some response, in keeping with its specific operational characteristics, when operating from 95% to 100% RC as illustrated by the dotted lines in Figure D1 & CC.A.3.

D.2 Compliance Testing Requirements

The main objectives of the governor/load controller response tests are to establish the plant performance characteristics for compliance with the Grid Code technical requirements (including the validation of plant data/models). They are also required to derive a set of reliable plant response values that will form the basis of response matrices for the Mandatory Services Agreement.

If a CCGT station has more than one identical module, the tests will be carried out on one of the complete modules. It will be acceptable in most cases to use the test derived matrices to cover the other modules if they have the same design and control characteristics.

It is required that a complete module is tested under normal operating mode (i.e. combined cycle) with the Gas Turbine Inlet Guide Vane (IGV) Control in operation. A frequency disturbance can be simulated by injecting the required frequency variation signals to both the governor speed reference point and the load controller target frequency set point (See Figure F1). An overview of the generic test sequence is described in Appendix F. The above guidelines form the basis of the tests. The test procedures are designed to be flexible to accommodate possible site operating conditions. However, any variations have to be agreed with National Grid.

D.3 Information on Recording Equipment

National Grid will provide one digital recording instrument on site during the National Grid witnessed test. A generic list of signals to be monitored during National Grid witnessed tests are provided in section D4 below. This will be used to monitor all plant signals at a sampling rate of 1 Hz or above. The station will also be required to provide its own digital recording equipment to record the above plant variables. This will provide a back up to the test results should one of the recording instruments fail at the time of testing.

The station is responsible for providing the listed signals to the User's and National Grid's recording equipment. For National Grid purposes the signals provided are required to be in the form of dc voltages within the range -10V to +10V. The input impedance of the National Grid equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.
It should be programmed for National Grid recording equipment to be on site one day prior to the test date. The station representatives are asked to check, prior to the arrival of the National Grid equipment, that a 230V AC power supply is available and that the signals are brought to robust terminals at a single sampling point.

Notes: Signals should be raw i.e. taken directly from a transducer or signal source. Should there be any problem; National Grid should be informed immediately.

D.4 Typical Governor Response Test Signal Schedules

The following tables give a typical set of signals to be recorded on CCGT, thermal and hydro-electric plant. The list is generic and therefore the schedules may be adjusted to suite site requirements although these should be discussed with National Grid prior to preparing the test procedures.

CCGT Plant (2 Gas Turbines + 1 Steam Turbine)

Signal No	Plant Parameter	Symbol	Unit	Unit Range *	Signal Range (V)*	Scaling Factor*	Offset
1	System Frequency / GT Speed	Fsys	Hz				
2	Injected GT1 Speed Reference	FGT1	Hz				
3	Output Power (for each GT/ST)	MW GT	MW				
4	Module Active Power	MWSO	MW				
5	GT Fuel Demand	FSR	%				
6	GT Fuel Valve Position	FSG	%				
7	GT Inlet Guide Vane Position	IGV	%				
8	GT Exhaust Gas Temperature	EGT	Deg C				
9	ST Pressure Before Turbine Valve	PTGV	BAR				
10	ST Valve Position	VP	%				
12	Stop / Start Logic Signal	ON/OFF					

*User Supplied

Thermal Plant

Signal No	Plant Parameter	Symbol	Unit	Unit Range *	Signal Range (V)*	Scaling Factor*	Offset
1	System Frequency / Machine Speed	Fsys	Hz				

2	Injected Frequency Signal	Finj	Hz				
3	Generator Output Power	MWGen	MW				
5	Governor Oil Pressure	SOP	BAR				
6	Turbine Governor Valve Position 1 (High Pressure)	TGV1	%				
7	Turbine Governor Valve Position 2 (Intermediate Pressure)	TGV2	%				
8	Pressure Set Point	PSP	BAR				
9	Superheater Outlet Pressure	PSH	BAR				
10	Pressure before Turbine Governor Valve	PBGV	BAR				
11	Pressure after Turbine Governor Valve	PAGV	BAR				
12	Boiler Firing Demand	BFD	%				
13	Stop / Start Logic Signal	ON/OFF					

*User Supplied

Hydro Electric Plant

Signal No	Plant Parameter	Symbol	Unit	Unit Range *	Signal Range (V)*	Scaling Factor*	Offset
1	System Frequency / Machine Speed	Fsys	Hz				
2	Injected Frequency Signal	Finj	Hz				
4	Speed Governor Demand Signal	GOV	%				
5	Actuator Output Signal	ACT	%				
7	Guide Vane / Needle Valve Position	GVP	%				
8	Other Control Parameters*						
9	Stop / Start Logic Signal	ON/OFF					
	Generator Output Power	MWGen	MW				

*User Supplied

D.5 Dual Fuelled Power Stations

For CCGT plants which are capable of running on alternative fuels, then additional governor response tests will be required to demonstrate performance when running on these fuels. Depending on plant design, detailed tests will be agreed between National Grid and the User at the early stage of the compliance process. This could be a subset of the tests indicated in Appendix F and a typical subset is shown in Figures F.2 and F.3 by encircled test numbers.

D.6 Bio-Fuelled Power Stations

A power station that runs on bio-fuel all the time and large enough to require frequency response performance, should undergo the full set of governor tests shown in Appendix F. If bio-fuel is used as a supplement to the main fuel then tests are necessary if the frequency response performance change. This could be a subset of the tests indicated in Appendix F and will be agreed between National Grid and the User.

D.7 Test Following DCS Replacement

If the DCS (Distributed Control System) of an existing plant is replaced it will be necessary to do some frequency response testing following such replacement. Assuming that there is no major change to response delivery, this could be a subset of the tests indicated in Appendix F and a typical subset is shown in Figures F2 and F3 by encircled test numbers. If the response of the unit has been changed then the full set of response tests will be required.

D.8 Tests on Auxiliary GTs

The tests required on a Auxiliary GT will depend on the required functionality of the OCGT before refurbishment (See Appendix G).

FIGURE D1 - MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE

(For a 0.5Hz frequency change from Target Frequency)

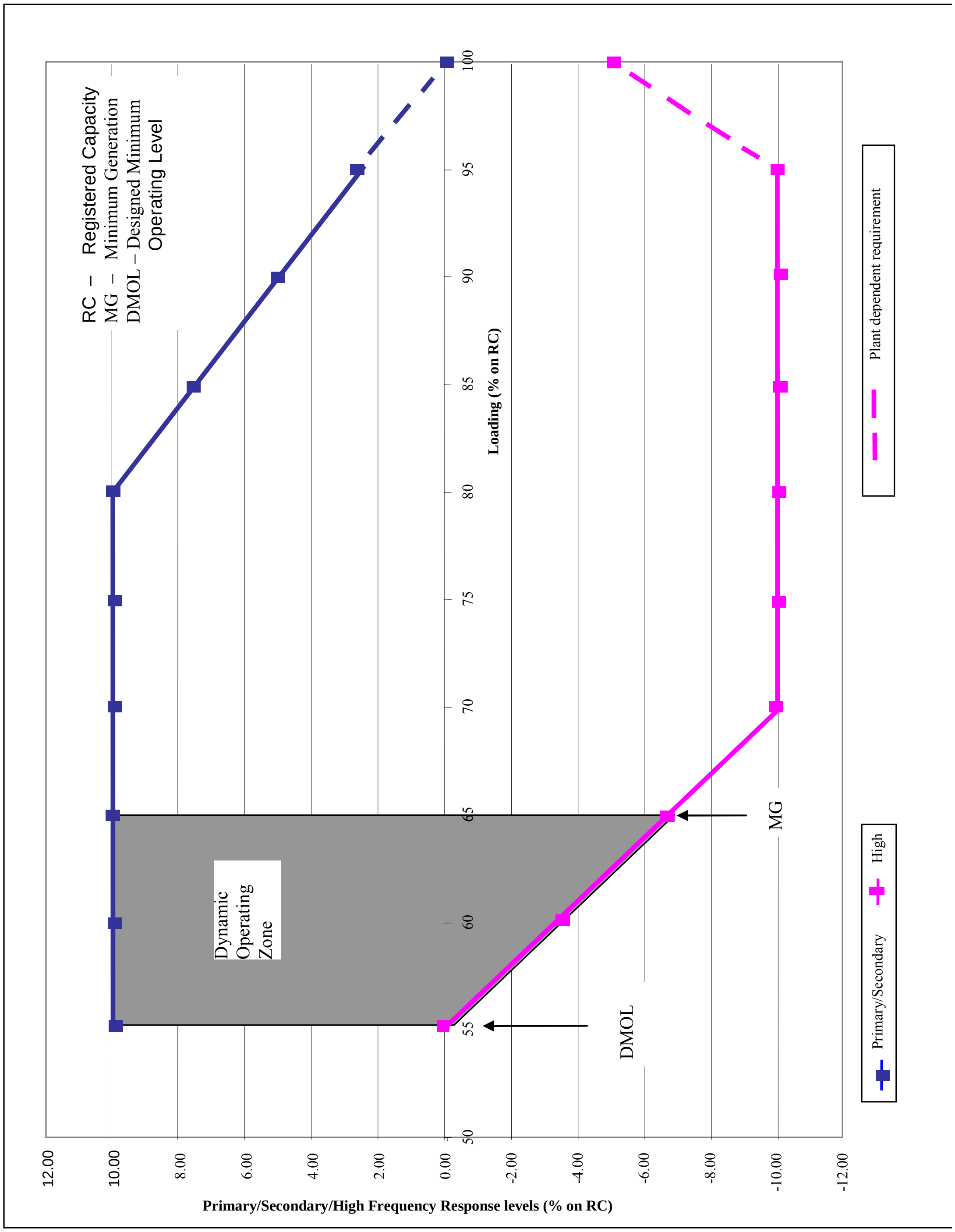


FIGURE D2 - INTERPRETATION OF PRIMARY AND SECONDARY RESPONSE VALUES

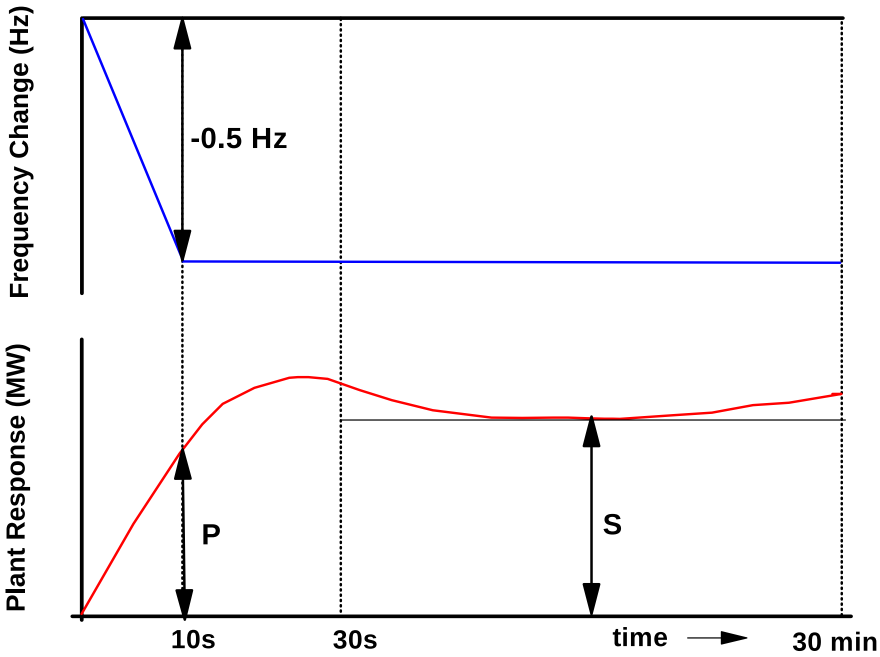
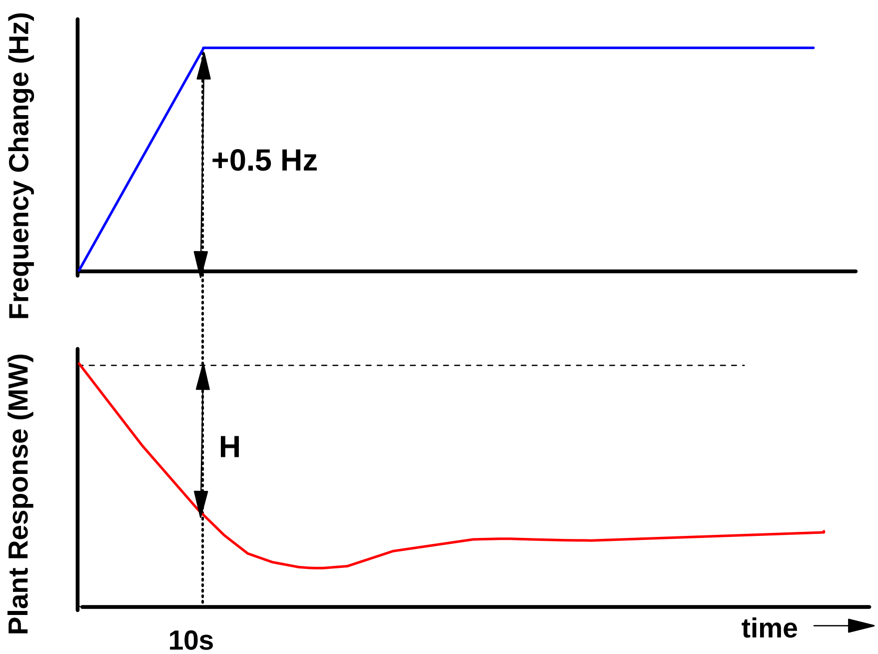


Figure D3 - Interpretation of High Frequency Response Values



APPENDIX E GOVERNOR / LOAD CONTROLLER REQUIREMENTS

The correct design and coordination of the governor and load controller (or module controller in the case of a Combined Cycle Gas Turbine (CCGT) plant) has been an important issue in compliance of the Grid Code and Mandatory Services requirements. The design details are site specific and there are many ways of meeting the requirements. This section helps to focus on the control issues and gives a simple description on the functional requirements which will help plant designers to appreciate the control needs.

E.1 Grid Code Target Frequency Setting Requirements

An Active Balancing Market Unit, irrespective of the plant type (conventional, thermal or CCGT, Grid Connected or Embedded), is required to have the facility to set the levels of generator output power and frequency. These are generally known as Target MW and Target Frequency settings. The former setting facility in the form of a 'Dial a MW' is generally available but the latter, in some cases, was missing from the initial design.

Under certain circumstances, an Active Balancing Market Unit may be instructed to operate with a Target Frequency of 50.00Hz. In order to adjust electric clock time the Grid Operator may instruct settings of 49.95Hz or 50.05Hz. However, under exceptional circumstances, the instructed settings could be outside this range. A minimum setting range from 49.90Hz to 50.10Hz is required.

E.2 Grid Code Mandatory Service Requirements

The target frequency setting facility, incorporated in the governor/load controller system, is essential not only for meeting the above scheduling and despatch requirements but also the plant performance to meet the Grid Code/Mandatory Services frequency response requirements.

E.3 Operating Configuration Options

Figure E1 shows a simplified schematic diagram of a governor/load controller for a gas turbine. The same control concept applies to conventional thermal plant and CCGTs. With the appropriate setting of the Auto/Manual and Frequency Compensated switches, three basic operating configurations (Figures E2A, E2B and E2C) can be obtained.

Configuration 'A' (Figure E2A) corresponds to manual governor operation and the generator output can be altered by manually adjusting the speed/load reference setting. This operating configuration is unacceptable since the target frequency setting is unavailable and the secondary response is unreliable (Figure E3) and does not meet the Grid Code/Mandatory Services requirements.

Configuration 'B' (Figure E2B) corresponds to automatic governor and load control. This configuration is unacceptable because of the unavailable target frequency facility and the unsustainable Secondary and High frequency responses (Figure E3).

Configuration 'C' (Figure E2C) corresponds to an automatic governor with frequency compensated load control. This configuration satisfies both the Grid Code and Mandatory Services requirements.

E.4 Conclusions

The above shows that the governor/load controller Target Frequency setting facility is essential to meet Grid Code and Mandatory Services requirements. Configuration 'C' (Figure E2C) is the acceptable operating option.

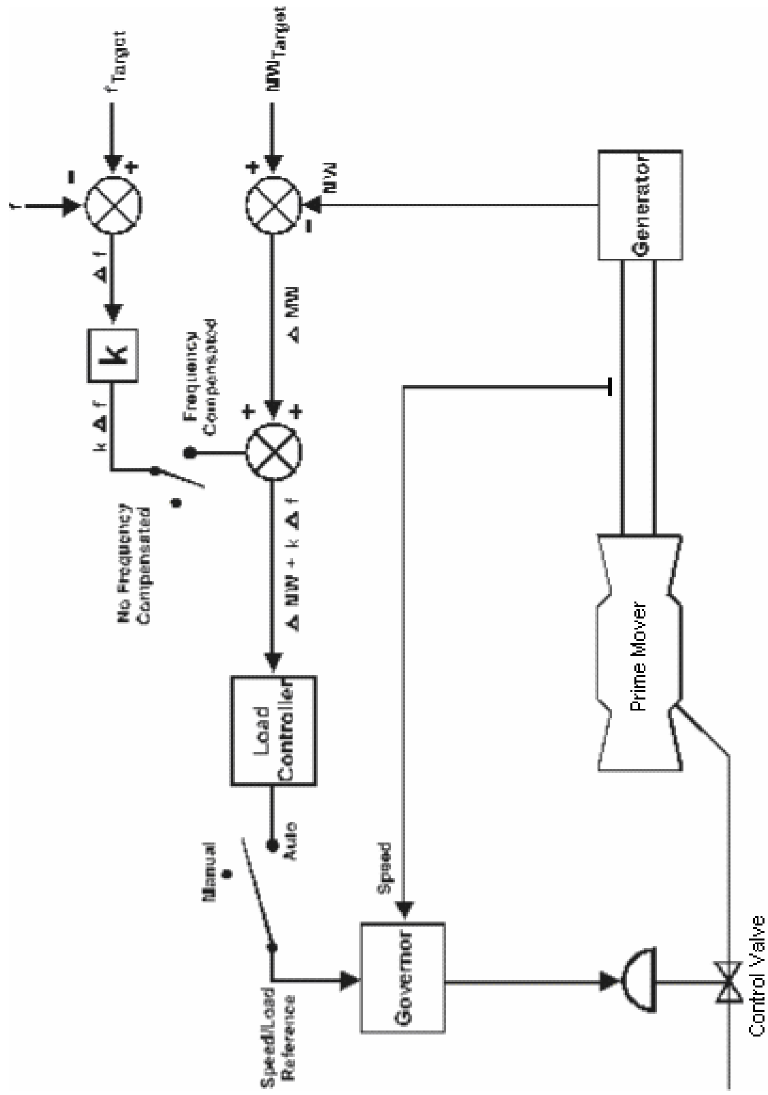


Figure E1 Schematic Diagram of Gas Turbine Governor/Load Controller

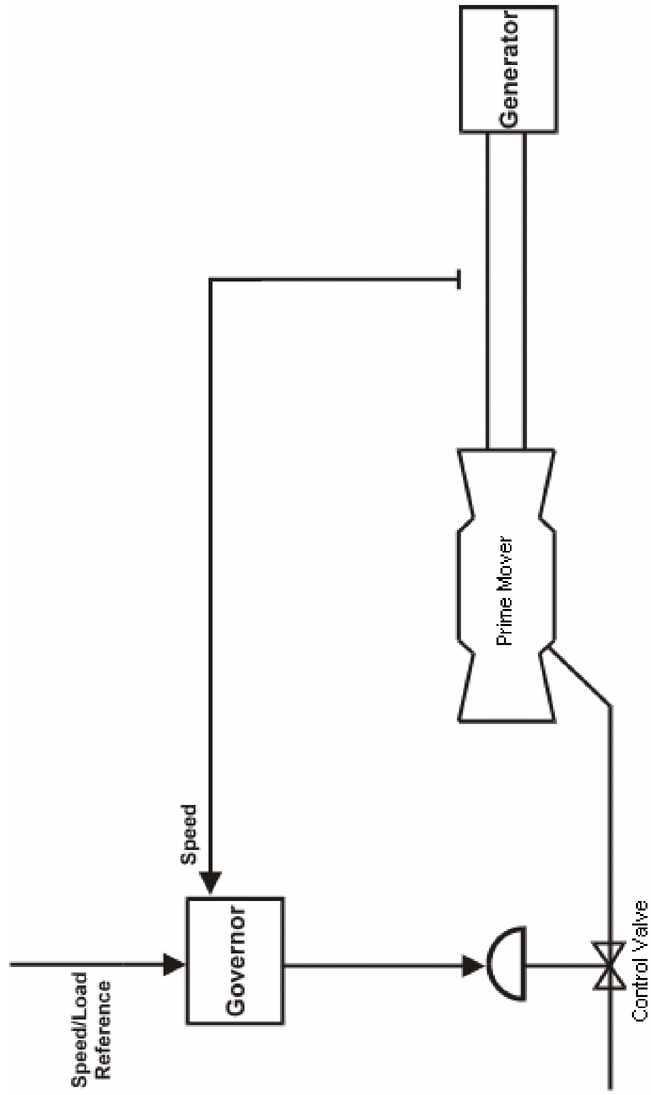


Figure E2A Governor without Load Controller

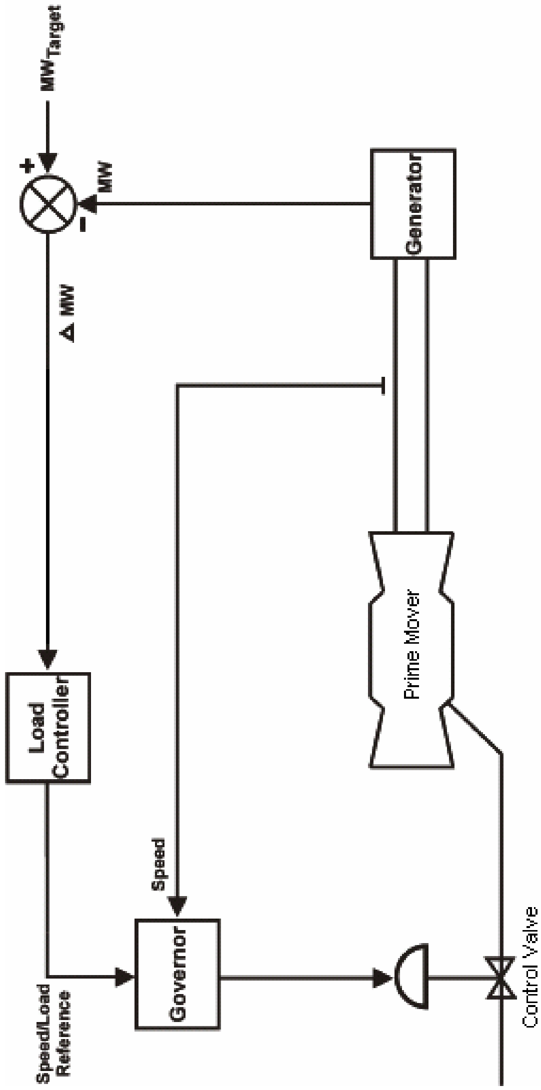


Figure E2B Governor with MW Target Correction

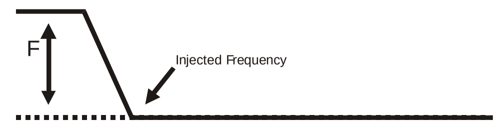
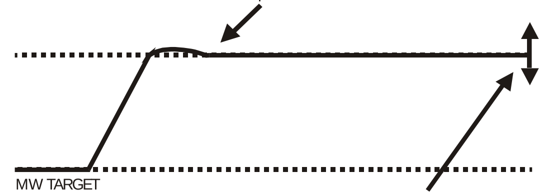
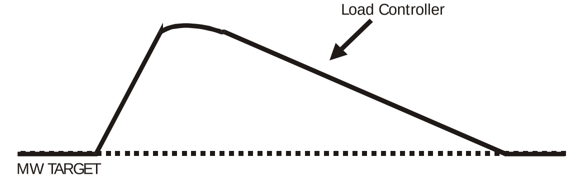
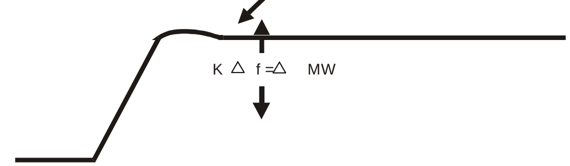
Configuration	Governor / Load Controller Operating Mode	MW Response to Frequency Variations
		
A (Figure E2A)	Governor without Load Controller Action	
B (Figure E2B)	Governor with Load Controller On MW Target Correction	
C (Figure E2C)	Governor with Load Controller On Frequency Compensated MW Target Correction	

Figure E3 Effect of Governor / Load Controller Configuration on Plant Response

APPENDIX F FREQUENCY RESPONSE TEST SCHEDULE

Past experience has demonstrated that significant delays can occur during testing because of problems associated with the governor/load controller set up or frequency injection method. Frequently this results in considerable lost time and additional expense for both parties. Consequently this test has been drawn up and has been shown to help in preventing such situations arising.

Typical injection locations at the governor and load controller are shown in Figure F1. In order to avoid the risk of re-testing, it is important that the injection method and the plant control are proved well in advance of the main tests by the station or site contractor. A preliminary test is therefore required with details given in section F1 below. For all tests, the target frequency selected on the generating plant is that instructed by the National Grid Control Centre. This should normally be 50.00Hz.

F.1 Preliminary Governor Frequency Response Testing

This should be done by performing preliminary tests. With the plant running at 75% of full load, the following frequency injections should be applied.

Test No	Frequency Injection	Notes
1	• Inject - 0.5Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injected signal	
2	• Inject +0.5Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injected signal	
3	• Inject -0.5Hz frequency fall over 10 sec • Hold for a further 20 sec • At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec. • Hold until conditions stabilise • Remove the injected signal	

The recorded results (e.g. Finj, MW and control signals) should be sampled at a minimum rate of 1 Hz to allow National Grid to assess the plant performance from the initial transients (seconds) to the final steady state conditions (5-15 minutes depending on the plant design).

The preliminary test results should be sent to National Grid for assessment at least two weeks prior to the final witnessed tests.

F.2 National Grid Witnessed Frequency Response Testing Schedule

Figures F2 and F3 give an overview of the ramps and step frequency injection tests required at different loading levels (i.e. MLP 6 to MLP 1). The corresponding test sequence is outlined below with the initial test establishing the maximum steady state output condition of the plant (i.e. MLP 6). A full generic procedure is provided in Appendix F.3 for reference.

1. Establish Maximum Plant Capacity as Loading Point MLP6

(a) Switch GT governors to manual and raise load demand to confirm the maximum output level at the base settings.

(b) Record plant and ambient conditions.

2. Response Tests at Loading Point MLP6 (Maximum Output)

(a) Operate the plant at MLP 6

(b) Inject ramp/profiled frequency changes simultaneously into the GT governor and load controller (i.e. Tests 1-4 in Figure F2) and record plant responses.

3. Response Tests at Loading Point MLP5 (0.95 RC)

(a) Operate the plant at MLP5.
(b) Conduct tests 5-7 as shown in Figure F2 and record plant responses.
(c) Conduct test A as shown in Figure F3 to establish the robustness of the control system under simulated extreme disturbances (as could occur under system islanding or system split conditions).

4. Response Tests at Loading Point MLP4 (0.8 RC)

(a) Operate the plant at loading point 4 (MLP 4).
(b) Conduct tests 8-14 as shown in Figure F2 and record plant responses.
(c) Conduct tests D - I as shown in Figure F3 to establish the GT dead band, and step response characteristics for governor modelling purposes.
(d) Conduct test J as shown in Figure F3 to establish the robustness of the control system under simulated extreme disturbances (e.g., system islanding or system split).

5. Response Tests at Load Point MLP3 (0.7 RC)

(a) Operate the plant at MLP3.
(b) Conduct tests 15 to 17 as shown in Figure F2 and record plant responses.

6. Response Tests at Minimum Generation MLP2 (0.65 RC)

(a) Operate the plant at MG.
(b) Conduct tests 18 - 22 as shown in Figure F2 and record plant responses.

7. Response Tests at Designed Minimum Operating Level MLP1 (0.55 RC)

(a) Operate the plant at DMOL.
(b) Conduct tests 23 - 26 as shown in Figure F2 and record plant responses.
(c) Conduct test K as shown in Figure F3 to establish the step response characteristics for governor modelling purposes.

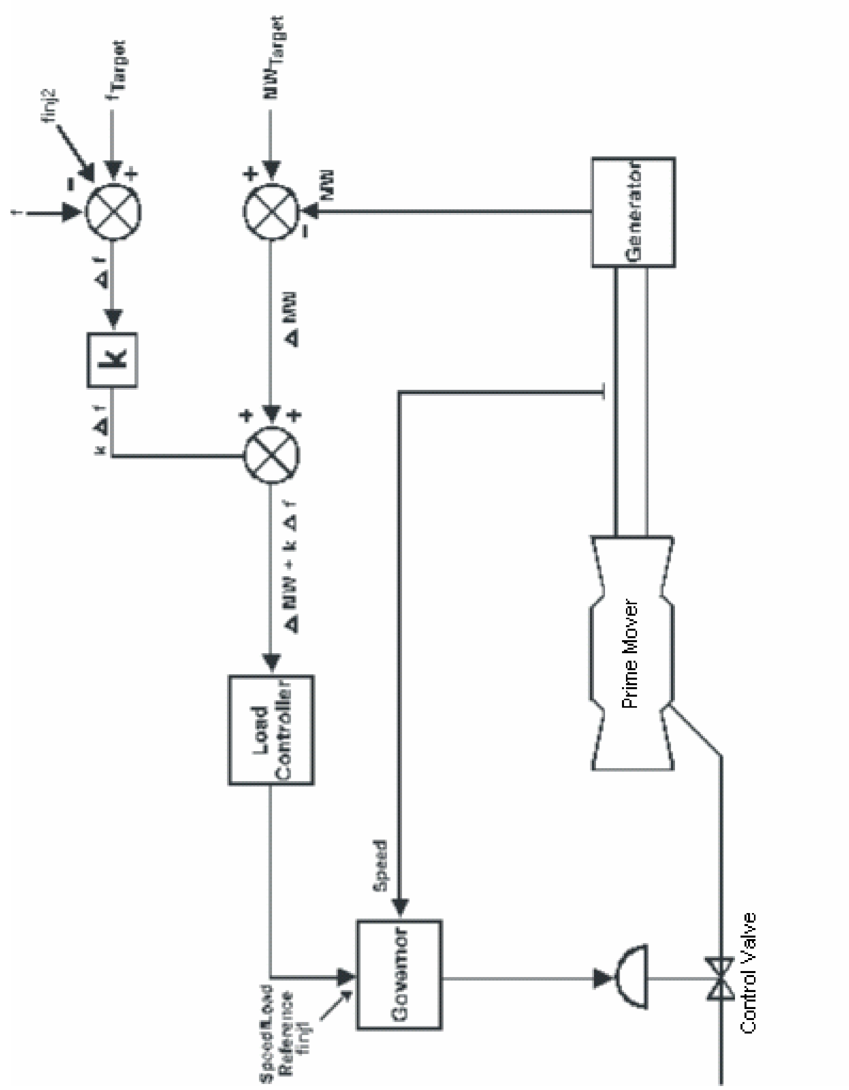
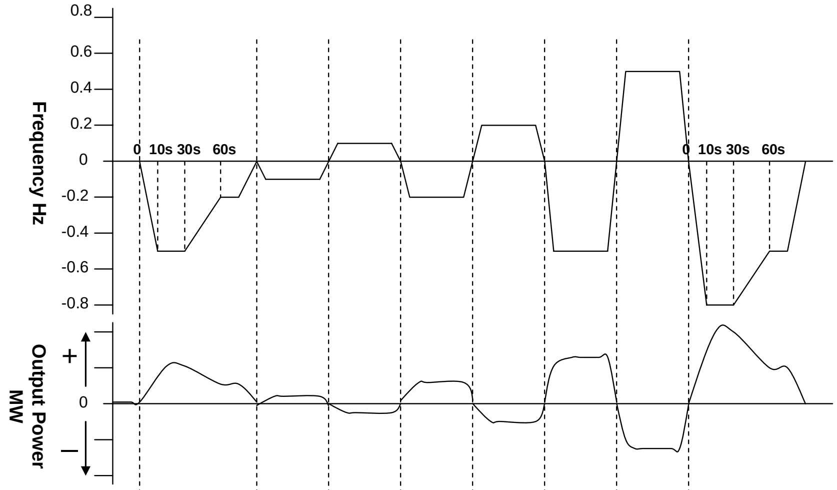


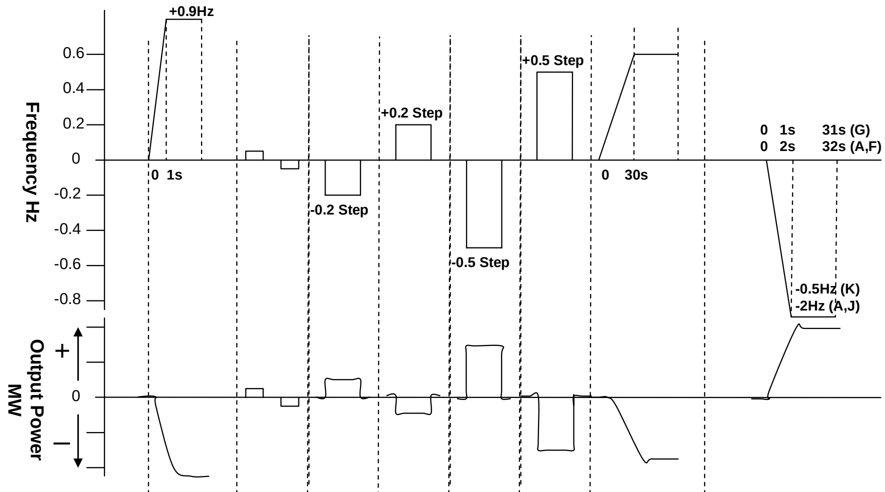
Figure F1 Governor with Frequency Compensated MW Target Correction



Notes:
Indicates subset
Refer App. D5 D7

Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

Figure F.2: Frequency Response Range Tests



Notes:
Indicates a subset
Refer to App D5 D7

Load Point	+0.9*	±0.02	-0.2	+0.2	-0.5	+0.5	+0.6	-0.5Hz -2.0Hz
MLP6	BC1						BC2	
MLP6 LFSM	BC3						BC4	
MLP5								A
MLP4		D/E	F	G	H	I		J
MLP3								
MLP2								
MLP1								K

Figure F.3: Frequency Response Range Tests

F.3 Generic Governor Frequency Response Test Schedule

Since the governor response tests described above are to be arranged and conducted by the User, it is their responsibility to propose a test programme to suit their site specific requirements. A typical example of the test programme is given in this Appendix. This programme is required to be submitted to National Grid for approval at the early stage of the compliance process.

Initial Checks on Maximum Plant Capability at MLP6, Plant in LFSM	
Step	**Actions**
1	Record plant MLP 6 condition including levels for GT's and ST and module MW output, ambient temperature, governor control signals and steam conditions.
2	Change GT governor control to manual and increase output power demand to maximum.
3	Record plant conditions when plant is thermally Stabilised.
4	Reset governor to normal operating mode and allow MLP 6 condition to be established

Injection Tests at MLP6, Plant in FSM				
Step	**Test No.**	**Action**	**Frequency Injection**	**Notes**
5 6	1	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.10Hz -0.10Hz	
7 8	2	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.20Hz +0.20Hz	
9 10	3	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.20Hz -0.20Hz	
11 12	4	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.50Hz -0.50Hz	
13 14	BC1	**Plant in FSM** • Inject +0.9* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.9 Hz * -0.9 Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
15 16	BC2	**Plant in FSM** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.1

		• Hold until conditions stabilise at MLP 6		
Switch to Limited Frequency Sensitive Mode				
17 18	BC3	**Plant in LFSM** • Inject +0.9* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.9 Hz -0.9 Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
19 20	BC4	**Plant in LFSM** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.2

*0.9Hz is needed to take an initial output 100% to a final output of 55%. If the initial output was not 100% and the DMOL is not 55% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output 95%
DMOL 45%
Governor Droop 4%
Frequency to be injected (0.95-0.45)x0.04x50 = 1Hz

Injection Tests at MLP 5, Plant in FSM				
21 22 23	5	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-0.50Hz +0.30Hz	
24 25	6	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-0.20Hz +0.20Hz	
26 27	7	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	+0.50Hz -0.50Hz	
28 29	A	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-2.0Hz +2.0Hz	To assess plant performance under islanding and system split Conditions

Injection Tests at MLP 4, Plant in FSM				
30 31 32	8	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50Hz +0.30Hz +0.20Hz	

33 34	9	• Inject -0.10Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.10Hz +0.10Hz	
35 36	10	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.10Hz -0.10Hz	
37 38	11	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.20Hz +0.20Hz	
39 40	12	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.20Hz -0.20Hz	
41 42	13	• Inject -0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50Hz +0.50Hz	
43 44	14	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.50Hz -0.50Hz	
45 46	D	• Inject -0.02Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.02Hz +0.02Hz	To assess the governor deadband
47 48	E	• Inject 0.02Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.02Hz -0.02Hz	To assess the governor deadband
49 50	F	• Inject -0.20Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.20Hz +0.20Hz	To assess step response characteristics of plant
51 52	G	• Inject 0.20Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.20Hz -0.20Hz	To assess step response characteristics of plant
53 54	H	• Inject -0.50Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.50Hz +0.50Hz	To assess step response characteristics of plant
55 56	I	• Inject 0.50Hz frequency rise as a step change • Hold until conditions stabilise at MLP 4 • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.50Hz -0.50Hz	To assess step response characteristics of plant
57 58	J	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at OLP	-2.0Hz +2.0Hz	To assess plant performance under islanding and system split conditions

Injection Tests at MLP 3, Plant in FSM				
59 60 61	15	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.50Hz +0.30Hz +0.20Hz	
62 63	16	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	+0.50Hz -0.50Hz	
64 65 66	17	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec. • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.80Hz +0.30Hz +0.50Hz	

Injection Tests at MLP2, Plant in FSM				
67 68 69	18	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50Hz +0.30Hz +0.20Hz	
70 71	19	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.20Hz +0.20Hz	
72 73	20	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	+0.20Hz -0.20Hz	
74 75	21	• Inject -0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50Hz +0.50Hz	
76 77 78	22	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.80Hz +0.30Hz +0.50Hz	

Injection Tests at MLP 1, Plant in FSM				
79 80 81	23	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.50Hz +0.30Hz +0.20Hz	

82 83	24	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.20Hz +0.20Hz	
84 85	25	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	+0.20Hz -0.20Hz	
86 87 88	26	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.80Hz +0.30Hz +0.50Hz	
89 90	K	• Inject -0.5Hz frequency fall over 1 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.5Hz +0.5Hz	To assess plant performance under islanding and system split conditions

APPENDIX G TESTING AUXILIARY GAS TURBINES

The following is a high level functional description of tests designed to demonstrate the robustness of the ex CEGB auxiliary OCGT's governor control system.

The tests are designed to check the integrity of the limits on the major control elements and to check the response and stability of the control systems to frequency disturbances.

Ref	Step	Description
		Tests at 100% load
GSD		Governor Speed Droop Test Adjust generator speed control loop gain so that a change in generator speed of 120 rpm changes the machine output from 100% load to full speed no load (FSNL). 120 rpm corresponds to 2 Hz and 4% droop. From 100% to FSNL decrease the speed reference in steps of 20 rpm until FSNL is achieved.
		Tests at 50% load
SC	 1 2 3	Speed Control Limit Test (if applicable) Reduce speed set point to just above that for the 50% load value. Apply a step increase to the generator speed reference to prompt the speed limit to control. Remove step and return set point to normal value. This test is only possible if speed is used as a control element.
CDP	 1 2 3	Compressor Discharge Pressure (CDP) Control Limit Test Reduce the CDP set point to just above that required for 50% load. Apply a step increase to the generator speed reference to prompt the CDP limit to control. Remove step and return set point to normal value
EGT	 1 2 3	Exhaust Gas Temperature (EGT) Control Limit Test Reduce the EGT set point to just above that required for 50% load. Apply a step increase to the generator speed reference to prompt the EGT limit to control. Remove step and return set point to normal value
D	1 2 3	Apply a -0.2Hz step the generator speed reference, hold for 60 sec or until conditions stabilise. Remove step and allow conditions to stabilise.
E	1 2 3	Apply a +0.2Hz step the generator speed reference, Hold for 60 sec or until conditions stabilise. Remove step and allow conditions to stabilise.
F	1 2 3	Apply a -0.5Hz step the generator speed reference Hold for 60 sec or until conditions stabilise. Remove step and allow conditions to stabilise.
G	1 2 3	Apply a +0.5Hz step the generator speed reference Hold for 60 sec or until conditions stabilise. Remove step and allow conditions to stabilise.

G.1 Typical Test Signal Schedules

The following tables give a typical set of signals to be recorded. This list is generic and therefore the schedules may be adjusted to suite site requirements and verification of the appropriate control system model. The list of signals to be provided should be included in the test procedure and discussed with National Grid.

	Unit	Signal* Range	Signal Representation*
Active Power Output	MW	0-10V	0 to 1pu
Speed	Rpm	±10V	1 ± 0.1pu
Compressor Discharge Pressure (each engine)	Bar	0-10V	0 to 1pu
Exhaust Gas Temperature (each engine)	C	0-10V	0.5 to 1pu
Fuel Demand (each engine)	%	0-10V	0 to 1pu
Fuel Valve Position (each engine)	%	0-10V	0 to 1pu

* Generator supplied

APPENDIX H SELF CERTIFICATION

H.1 Compliance Statement Summary Front Sheet

This summary front sheet is required to certify that the Power Station is compliant with the Grid Code Connection Conditions and Technical Appendices of the Bilateral Agreement in all aspects other than any exceptions listed.

Power Station:	[NAME]	**Generator:**	[GENERATOR]	**Registered Capacity (MW):**	[MW]
Connected to:	[NETWORK GENERATOR]	network at	[SSTN NAME]	substation	
Main Contractor:	[CONTRACTOR]		**Synchronous Generator Manufacturer :**	[GENERATOR MANUFACTURER]	

This Report records the compliance of [NAME] Power Station with the Connection Conditions of the Grid Code and the technical requirements of the Bilateral Agreement.

National Grid Company's specific requirements and guidelines for demonstrating compliance are set out in the following pages. We have recorded our compliance against each item, together with references to supporting evidence and a commentary where this is appropriate.

Supporting evidence, in the form of simulation results, test results, manufacturer's data and other documentation, is attached as Appendices.

[GENERATOR] certifies that the [NAME] Power Station is compliant with the Connection Conditions and Technical Appendices of the Bilateral Agreement in all aspects, with the following exceptions and queries:

Statement No.	**Connection Condition**	**Requirement**	**Ref:**	**Issue**

Compliance certified by:

Name:
[PERSON]
Signature:
[PERSON]
Date:
[DATE]

Title:
[PERSON DESIGNATION]
Of
[GENERATOR]

G2 Compliance Statements

Compliance Statement

Syn NR Test2 Generator transmission connected in National Grid transmission area

Completion Date on 01/02/2008

Connection Voltage = 400kV, Registered capacity = 500MW

Generation Type : Synchronous Plant

Key to Evidence Requested

'DS'	Indicates that National Grid would expect to see the results of a Dynamic Simulation study.
'G'	Manufacturer's generic data or test results, as appropriate.
'D'	Copies of correspondence or other documents confirming that a requirement has been met (e.g. copy of letter from National Grid confirming receipt of Safety Rules)
'O'	Indicates that National Grid would expect to be provided with the currently applied operating settings.
'S'	Indicates that National Grid would expect to see the results of a Simulation study (not necessarily, but not excluding, dynamic simulation).
'P'	Generating Unit design data.
'T'	Indicates that National Grid would expect to see results of, and/or witness, tests or monitoring which demonstrates compliance. Where possible, the test is referenced to the relevant section of this guidance document.
'TV'	Indicates type validation test (if Generator pursues this compliance option)

Key to Compliance: Y = Yes (Compliant), N = No (Non Compliant) or Q = Query

REQUIREMENT					RESPONSE	
Connection Condition	**Compliance Requirement of User**	**Evidence Requested**	**Lead Role**	**UDL Ref**	**Compliance Y, N or Q**	**User's Statement**
CC.5.2	Please confirm that the following information has been submitted to National Grid:					
	(a) Updated Planning Code Data, with any estimated values replaced by validated plant data;	P, G, D	SO	2.1 3.1-3.4 4		
	(b) Details of Protection (see CC.6.2);	P	TO	2.1.2		
	(c) Copies of Safety Rules and Local Safety Instructions (see CC.7.2.6) applicable at the User Site;	D	TO	1.2, 1.10		

	(d) Information to enable National Grid to prepare Site Responsibility Schedules (e) An Operation Diagram (see CC.7); (f) The proposed Name of the User Site; (g) written confirmation that Safety Coordinators are authorised and competent pursuant to OC8; (h) RISSP prefixes, pursuant to requirements of OC8; (i) A list of telephone numbers for Joint System Incidents; (j) List of managers authorised to sign Site Responsibility Schedules; (k) Information to enable National Grid to prepare Site Common Drawings (see CC.7); (l) A list of telephone numbers of Fax machines (see CC.6.5.9);	D D D D D D D D D	TO TO SO/TO TO TO SO TO TO SO	1.5 1.6 1.13 1.10 1.11 1.12 1.5 1.7 1.13		
CC6.1.5	Voltage Waveform Quality (b) Phase Unbalance Confirm that the Synchronous Machine and other components can withstand 2% Phase (Voltage) Unbalance as specified in Grid Code CC.6.1.5 (b) and CC.6.1.6. (That is, the rms negative phase sequence (nps) voltage at the busbar is 2% of the rms value of the positive phase sequence (pps) voltage.)	D	TO	2.8		
CC.6.2.1.1 **(b)**	Earth Fault Factor: Confirm that the plant can withstand a phase voltage falling to zero or rising to 140% nominal phase-to-earth voltage during a single- or two phase-to-earth fault on the GB Transmission System.	P, G	TO	1.4		

	Confirm that the plant can withstand, without tripping, the transient voltage conditions advised by National Grid	P, G				
CC.6.2.1.2	Substation Plant and Apparatus:					
(a) - (d)	Confirm that the plant and apparatus within the Transmission Licensee's Transmission busbar protection zone complies with the appropriate technical specifications	D	TO	2.1		
(e)	State the single and three-phase fault interruption ratings of the User's circuit breaker connecting the Generator to the GB Transmission System. Confirm that the circuit breaker can withstand the short circuit current at the Connection Point published in the Seven Year Statement for future years	P, G	TO	2.1		
CC.6.2.2.2.2	Fault Clearance Times:					
(a)	Confirm that the fault clearance time, for faults on the User's equipment directly connected to the GB Transmission System, and for faults on the GB Transmission System directly connected to the User's equipment, is less than or equal to the time specified in the Bilateral Agreement. State the fault clearance time.	P, G, D	TO	2.1.2		
	State the probability of fault clearance within the maximum time specified in the Bilateral Agreement	P, G, D				
(b)	Confirm that back-up protection is installed.	P, D	TO	2.1.2		

	State the back-up fault clearance time at the minimum infeed for normal operation for faults on the HV Connections. The minimum HV system fault infeed is given on the Information Sheet provided.	P, G, D				
	Confirm that the back-up fault clearance time is no more than 800 ms.	P, G, D				
	Confirm the required Discrimination of back-up protection	P, G, D				
(c)	Confirm the provision of circuit breaker fail protection on the circuit breaker connecting the generator to the GB Transmission system (the 'connecting circuit breaker').	P, G, D	TO	2.1.2		
	Confirm that this protection will initiate tripping of all necessary circuit breakers within 200 ms of the end of the Fault Current Interruption time if the 'connecting circuit breaker' fails to clear a fault.	P, G, D				
(d)	Confirm the System Fault Dependability Index for the User's protection system as a whole is not less than 99%					
CC.6.2.2.3.1	Protection of Interconnecting Connectors: Confirm the provision of Protection equipment for interconnecting connections, as specified in the Bilateral Agreement.	D	TO	2.2.2		
CC.6.2.2.3.2	Circuit-breaker Fail Protection Confirm the provision of circuit-breaker fail protection as specified in the Bilateral Agreement.	P, D	TO	2.1.2		

	If the Generator includes pressurised head air-blast circuit breakers, please confirm that a back-trip signal is provided in the event of loss of air from these circuit breakers.	P, D				
CC.6.2.2.3.3	Loss of Excitation Confirm that protection exists to detect the loss of excitation of the generator and initiate tripping	P, D		2.1.2		
CC.6.2.2.3.4	Pole-Slipping Protection If Specified as a requirement in the Bilateral Agreement, confirm that Pole Slipping Protection has been fitted	P, D		3.5		
CC.6.2.2.3.5	Signals for Tariff Metering: Confirm the provision of current and voltage transformers providing signals for tariff metering	D	SO	2.5		
CC.6.2.2.4	Work on Protection Equipment Confirm that appropriate working procedures have been set up and agreed with National Grid.	D	SO	2.1.2		
CC.6.2.2.5	Relay Settings:					

	Confirm that Protection and relay settings across the Connection Point are in accordance with the Bilateral Agreement.	D	TO	2.1.2		
CC.6.3.2	Reactive Power: Confirm all Synchronous Generating Units are capable of supplying Rated MW at any point between the limits 0.85 Lagging and 0.95 Leading Power Factor Measuring the active and reactive power at the unit terminals, carry out test 6. Confirm the units reactive capability Confirm the short circuit ratio is below 0.5 Provide a performance chart as specified in OC.2.4.2.1 (a) which reasonable reflects the true operating characteristics of the plant. Please submit the chart in accordance to Appendix 1 of OC.2. If Applicable, indicate the effect of the ambient temperature on these figures	 T4.6 G, T4.2 P, G	 SO	 3.6.1		
CC.6.3.3	Power Output/Frequency Characteristic: Confirm that Active Power output is independent of system frequency for frequency changes within the range 49.5 to 50.5 Hz. Include Characteristics which demonstrates the capability of the plant over a range of ambient temperatures up to 25 ºC.	 P, G	 SO	 3.1.2		

	Confirm that any reduction of power output due to frequency reductions at frequencies between 49.5 and 47 Hz is less than that specified in Figure 2 of CC.6.3.3 of the Grid Code. Include test data to demonstrate the characteristic	P, G, T4.9				
CC.6.3.4	Voltage Range: For Synchronous Plant Confirm that MW changes due to changes in voltage at the Grid Entry Point are no more than would result from changes in active power losses due to the changes in voltage. Confirm by calculations that the Generator can deliver the required reactive power range when the connection point voltage, 400kV, 275kV, 132kV or lower, varies by +/- 5%	 G G				
CC.6.3.5	Black Start: See Bilateral Agreement to see if Black Start capability is required If applicable, provide a detailed technical statement of how the facility will be provided. Testing of Black Start facilities will be co-ordinated by National Grid System Requirements Confirm whether or not independent power supplies are provided for jacking and barring gear					

CC.6.3.6	Control Arrangements (general):					
(a)	Frequency Control: Confirm that the requirement for frequency control can be met	G	SO	3.1.2		
(b)	Voltage Control: Confirm that the requirement for reactive power control can be met	G, P	SO	3.1.2		
CC.6.3.7	Frequency Control:					
(a)	Confirm that the Generating Unit is fitted with a fast-acting proportional frequency control device and unit load controller or equivalent control device to provide frequency response under normal operating conditions	P, G T4.9	SO	3.1.2		
	State the European Specification, or other standard, to which the frequency control device is manufactured.	P, G				
BC.3.7.2	Generating Unit operating in Limited Frequency Sensitive Mode. .		SO	3.6.3		
	Confirm that: (i) Active power output remains constant up to 50.4Hz	T BC3 (App F)				
	(ii) Above 50.4 Hz, active power is reduced, by at least 2% for each 0.1 Hz increase in frequency above 50.4 Hz.					
	Provide results of the tests					

(b)	Carry out Tests as per Figure F3: Operate the Generating Unit in Frequency Sensitive Mode at an active power output midway between Designed Minimum Operating Level and Register Capacity).	T7				
	Confirm that the frequency control device operates with stability for each frequency change.	T7				
	Confirm that the deadband is no greater than +/- 0.015Hz	TC, D				
(c)	Carry out Test A, H, I: Operate the generator in Frequency Sensitive Mode Inject a series of rapid ramp changes of frequency reference, at different module active power outputs, as detailed in the Guidance Document.	T A, H, I				
	Confirm that the frequency control device operates with stability for each frequency change.					
	Provide results of the tests	T A, H, I				
	Hence confirm and demonstrate that the plant will control the frequency at or below 52 Hz under islanded conditions. Also confirm and demonstrate that the plant will not trip unless the high frequency response would result in operation at less than DMOL.	P, G				
(d)	Confirm the existence of a Target Frequency setting facility. State whether it is (a) continuous or (b) stepped.	P, G	SO	3.1.2		
	Please provide details of the setting range and confirm that it covers at least 50 +/- 0.1 Hz.	P, G				
	If control is stepwise, please state the step size and confirm that it is no more than 0.05Hz.	P, G, O				
	The following performance requirements must also be met from 1/01/06 onwards:					

App. 3 CC.A.3.2	Confirm the Minimum Generation of the Generating Unit, and confirm that it is not more than 65% of the Registered Capacity	P, G				
	Confirm the Designed Minimum Operating Level of the Generating Unit and confirm that it is not more than 55% of the Registered Capacity.	P, G				
CC.A.3.3 CC.A.3.4	Carry out Tests as labelled in Figure F2 Operate the Generating Unit in Frequency Sensitive Mode at a series of different operating levels between Designed Minimum Operating Level and Registered Capacity.	T1:26	SO	3.6.3		
	At each operating level, inject a series of signals into the frequency control device to simulate changes in system frequency. Measure the active power response from the Generating Unit.	T1:26				
	Confirm that:					
	(i) Active Power Responses to 0.5 Hz frequency changes at each operating level are not less than the minimum requirement set out in CC.A.3.3 and Fig CC.A.3.1	T1:26				
	(ii) Active Power response to frequency changes less than 0.5 Hz are in linear proportion to the response for 0.5 Hz. E.g. the response for a 0.2 Hz change should be 40% of that for 0.5 Hz.	T1:26				
	(iii) Active Power response to frequency changes greater than 0.5 Hz are at least equivalent to the 0.5 Hz change					
	Provide results of the tests	T1:26				

CC.A.3.5	From the results of Test 1:26, confirm that the full response capability of the Generating Unit can be restored within 20 minutes following a frequency disturbance.	P, G, S T1:26				
CC.6.3.8	Voltage Control:					
(a)	Confirm the existence of a continuously-acting automatic excitation control system providing constant terminal voltage					
(b)	Confirm the existence, or otherwise, of a Power System Stabiliser facility in the Generating Unit control system.	P, G	SO	3.1.2		
	If a PSS facility exists, please confirm that it is disabled or otherwise that it is set up and commissioned in accordance with the Bilateral Agreement (Note: if a PSS is required, National Grid will define and witness commissioning tests in accordance with BC.2.11.2)	O				
	Confirm and demonstrate that the voltage control system is stable and damped for voltage step-changes that would drive the controller against reactive limits	P, G				
	Carry out Test 4.3 imposing step changes on the voltage control system, by tap-changing and/or by injecting signals into the voltage control loop		SO	3.6.2		
	Provide test results as detailed in the description of Test 3 in the Guidance Document	T 4.3				

	GB transmission system parameters for use in simulations of transient response are advised by National Grid in the Bilateral Agreement.					
	Confirm the existence, or otherwise, of constant reactive power control or constant power factor control facilities in the generator voltage control system.	P, G	SO	3.1.2		
	If such facilities exist, and the Bilateral Agreement requires their use, please state the settings required by the Bilateral and the settings applied. Otherwise confirm that they are disabled.	O				
	GB transmission system parameters for use in simulations of transient response are advised by National Grid in the Bilateral Agreement.					
	Confirm the existence, or otherwise, of constant reactive power control or constant power factor control facilities in the generator control system.	P, G	SO	3.1.2		
	If such facilities exist, and the Bilateral Agreement requires their use, please state the settings required by the Bilateral and the settings applied. Otherwise confirm that they are disabled.	O				
CC.6.3.9	Steady State Load Inaccuracies					
	State the standard deviation of Load error for the Generating Unit over a 30 minute period, assuming constant mechanical power input.		SO	3.1.2		

	Confirm that this standard deviation is no more than 2.5% of the Generating Unit's Registered Capacity. Test 4.6 can be used to confirm this.	T4.6				
CC.6.3.10	Negative Phase System Loadings: Confirm each generator can withstand, without tripping, the negative sequence loading incurred by clearance of a close up phase to phase fault, by system backup protection on the GB Transmission System or User System if Embedded.		N/A			
CC.6.3.11	Neutral Earthing: Transmission-connected Generators at 132kV or higher voltage Confirm that the HV winding of each transformer) connecting the Generating Unit to the System is star connected and that the star point is suitable for connection to earth. Confirm that the earthing and lower voltage winding arrangements are such as to ensure that the Earth Fault Factor requirement of CC.6.2.1.1 (b) will be met.	P P	TO	1.3 2.1.1		
CC.6.3.12	Frequency-Sensitive Relays: State the operating frequency ranges for the Generating Unit, its constituent elements and other components.	P, G	SO/TO	2.1.2		

	Confirm that all plant within the Generating Unit can operate safely over the frequency ranges and durations specified in CC.6.1.3 Confirm the existence, or otherwise, of any frequency-level and/or rate-of-change-of-frequency relays. Either Confirm that any such frequency-sensitive relays are set to operate outside the frequency ranges specified in CC.6.1.3. Please state the settings Or Confirm that any such frequency-sensitive relays are set in accordance with the Bilateral Agreement. Please state the settings.	P, G P, G P, G O P, G O				
CC.6.3.13	Frequency Excursions outside 47 – 52 Hz: Confirm acceptance of responsibility for protecting the Generating Unit, its constituent elements and other components in the event of a frequency excursion outside the range 47 – 52 Hz	D	SO	2.1.2		
CC.6.3.14	Fast-Start: Not applicable					
CC.6.3.15	Fault ride-through:					

(i)	Confirm that the excitation system fitted to the Generating Unit complies with the requirements advised by National Grid		SO	3.6.4 3.7.4		
(ii)	Confirm that Generating unit protection will not cause the unit to trip for the voltage dips described by CC.6.3.15					
CC.6.5.4	Control Telephony: Confirm that control telephony is provided and installed in accordance with the Bilateral Agreement	D	SO/TO	1.8		
CC.6.5.6	Operational Metering Confirm that Operational Metering is provided and installed in accordance with the Bilateral Agreement	D	TO	2.4		
CC.6.5.7	Instructor Facilities: Confirm that accommodation is provided for National Grid Instructor Facilities	D	SO	1.8		
CC.6.5.8 **(a)**	Electronic Data Communication (EDT) Facilities: If the User is a BM Participant Confirm that electronic data transmission facilities have been provided and installed.	D	SO	2.6		

(b)	Confirm that electronic data logging facilities are installed.	D				
CC.6.5.9 **(a)**	Facsimile Machines: Confirm the provision of facsimile machines at the Control Point, and at the Trading Point, of the generator.	P	SO	1.13		
CC.6.5.11	Bilingual Message Facilities: Not Applicable					
CC.6.6.1	System Monitoring: If a requirement for System Monitoring has been agreed with National Grid.: Confirm the provision of signals from the Generating Unit for system monitoring, and space for system monitoring equipment.	P	SO	2.7		
CC.7.2.6	Safety Rules I: Please confirm that you have received copies of National Grid Safety Rules that will apply to your staff working on the connection site.	D	TO	1.2		
CC.7.2.7	Safety Rules II:					

	Please confirm that the Site Responsibility Schedule submitted under CC.7.3.1 and CC.7.3.2 records the Safety Rules that apply to each item of Plant and/or Apparatus	D	TO	1.2		
CC.7.3.1, CC.7.3.2	Site Responsibility Schedule: Please attach the Site Responsibility Schedules and confirm that these have: (i) been prepared in accordance with Appendix CCA.1 of the Grid Code, and (ii) been provided to National Grid.	D	TO	1.5		
CC.7.4.1 – CC.7.4.3, CC.7.4.7, CC7.4.8	Operation Diagram: Confirm the preparation and provision of an Operations Diagram in accordance with the requirements of CC.7.4.2, CC.7.4.7 and CC.7.4.8. The diagram should use the symbols shown in Appendix 2 Part 1A. of the Connection Conditions. The diagram should include the apparatus, and follow the principles, set out in Appendix 2 Part 2 of the Connection Conditions. [Ref to OC11?]	D	TO	1.6		

CC.7.4.4 – CC.7.4.6, CC.7.4.9	Gas Zone Diagram: (where applicable) Confirm the preparation and provision of a Gas Zone Diagram in accordance with the requirements of CC.7.4.4 - CC.7.4.6 and CC.7.4.9. The diagram should use the symbols shown in Appendix 2 Part 1B. of the Connection Conditions. The diagram should follow the basic principles set out in Appendix 2 Part 2 of the Connection Conditions.	D	TO	1.6		
CC.7.5	Site Common Drawings: Confirm arrangement and provision of site common drawings Attach a copy of the drawings	D	TO	1.6		
CC.7.6	Access: Please confirm that arrangements for access to the connection site have been agreed with National Grid and recorded in the Interface Agreement	D	TO	1.1		
CC.7.7	Maintenance Standards:					

	Please acknowledge responsibility to maintain, and test, all User's plant and apparatus and to ensure that they remain rated for the duty required.	D	SO/TO	1.15		
CC.7.9	Control Point: Confirm the provision of a Control Point for the Generating Unit Confirm that the Control Point will be continuously manned. State the location of the Control Point.	 D D P	 SO	 1.13		
CC.8.1	System Ancillary Services Confirm the capability to provide System Ancillary Services as follows: Reactive Power: Confirm that the generator meets the requirements of CC.6.3.2 and CC.6.3.4. Demonstrate the capability by means of test results (see Statement No 12, CC.6.3.2) if available or by calculation or simulation study using validated plant and system data. Frequency Response: Confirm that the generator meets the requirements of CC.6.3.7.					

	Provide a validated frequency response capability diagram in the format of Fig. CC.A.3.1 in Appendix 3 of the Connection Conditions.		SO	A.5		
CC.8.2	Commercial Ancillary Services Confirm the availability or otherwise of Commercial Ancillary Services.		SO	A.5		
BCA - F5	Bilateral Connection Agreement Appendix F5 Confirm the availability or otherwise of Commercial Ancillary Services.		SO	A.5		

APPENDIX ICONTACT NAMES & ADDRESSES

There are a number of different parts of National Grid, each with key areas of expertise and responsibilities relevant to connection of a Generator. The complete process is controlled by the Commercial Contact. A Commercial Contact is assigned to each new connection and should be the first point of contact in the event that the appropriate contact has not been identified. The Commercial Contacts all report to the "Electricity Customer Manager", who is responsible for allocating the Commercial Contacts to specific connections. The contact details for the Electricity Customer Manager, is listed below:

Stuart Easterbrook – Electricity Customer Manager – Tel: 01926 65 6213
Email: stuart.easterbrook@uk.ngrid.com

The Generator Dynamic Performance Team is responsible for the majority of the technical aspects related to Generation. An engineer from this team will be assigned to each new connection by the team leader. The contact details of the team leader are listed below:

Helge Urdal – Generator Dynamic Performance Manager – Tel: 01926 65 4601
Email: helge,urdal@uk.ngrid.com

The responsibility for DRC guidance and week 24 data submission process lies with Network Strategy department. The contact details of its departmental head are listed below:

Keith Dan – Analysis Systems and Data Team Leader – Tel: 01926 65 5336
Email: keith.dan@uk.ngrid.com

As described in the earlier sections of this document, the users submit the data to the Commercial Contacts in a standard format known as the User Data Library (UDL) which is divided into 5 major sections. These in turn, are further divided into related subsections. The following lists senior contacts within National Grid for the five major sections and where appropriate details more appropriate contacts relating to specific topics within those sections.

Part A – Commercial & Legal – Stuart Easterbrook (see above for details)

In relation to the following specific topics please refer to the associated contact:

Toga Registration–Jeremy Caplin 01189 363288 jeremy.caplin@uk.ngrid.com
Mandatory Service Agreement–David M Smith 01926 655534 Dave.M.Smith@uk.ngrid.com
Codes for Balancing and BMU Registration–Sue Stewart 01189 363124 email sue.stewart@uk.ngrid.com
Balancing Mechanism Process–Neil Sutton 01189 363147 neil.sutton@uk.ngrid.com
Ancillary Service Monitoring–Alex Carter 01189 363493 alex.carter@uk.ngrid.com

Part 1 – Safety & System Operation

The Transmission Owner is the main point of contact for the Safety and System Operation section. Where National Grid is the Transmission Owner, Commercial Contacts are the interface for all subsections relating to Part 1.

In relation to the following specific topics please refer to the associated contact:

Contact Details & Joint System Incidents Telephone Numbers – Neil Sutton (see above)

Part 2 – Connection Technical Data and Compliance

The Transmission Owner is the main point of contact for the Connection Technical Data and Compliance section. Where National Grid is the Transmission Owner, the Commercial Contacts are the interface for all subsections relating to Part 2.

In relation to the following specific topics please refer to the associated contact:

Tariff Metering–Elexon 020 7380 4222 helpdesk@elexon.co.uk
Operational Communications (EDL & EDT) – Neil Sutton (see above)
Ancillary Services Monitoring – Alex Carter (see above)

Part 3 – Generator Technical Data and Compliance – Helge Urdal (see above for details)

In relation to the following specific topics please refer to the associated contact:

DRC Schedule 2 – Jeremy Caplin (see above)
DRC Schedule 14 – Keith Dan 01926 655336 keith.dan@uk.ngrid.com
Site Specific Technical Data and Compliance – Neil Sutton (see above)

Part 4 – General DRC Schedule – Commercial Contact

In relation to the following specific topics please refer to the associated contact:

DRC Schedule 3 & 6 – Jeremy Caplin (see above)
DRC Schedule 8 – Sue Stewart (see above)

Contact Address:

National Grid, National Grid House, Warwick Technology Park, Gallows Hill, Warwick CV34 6DA

National Grid

National Grid is an international energy delivery business whose principal activities are in the regulated electricity and gas industries.

National Grid is the Great Britain System Operator and owns and develops the high-voltage electricity transmission network in England & Wales.