nationalgrid

Guidance Notes –

Power Park Modules

Issue 3
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Foreword

These Guidance Notes have been prepared by National Grid Electricity Transmission (NGET) to describe to Generators how the Grid Code Compliance Processes should work.

These Guidance Notes are prepared, solely, for the assistance of prospective Generators connecting directly to the National Electricity 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 5, Revision 0, effective from the 17 August 2012. They have been developed from Issue 11 of the Guidance Note of September 2008 and reflect the major changes brought about by Grid Code revision A/10 as approved by the regulator on 26 July 2012.

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

The Electricity Customer Manager (see contact details) will be happy to provide clarification and assistance required in relation to these notes and on Grid Code compliance issues.

National Grid welcomes comments including ideas to reduce the compliance effort while maintaining the level of confidence. Feedback should be directed to the National Grid Generator Compliance team at:

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Email: box.gdpsharedmailb@nationalgrid.com

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
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
STC	System Operator Transmission Owner Code
TO	Transmission Owner
TOGA	Transmission Outages, Generation Availability
UDFS	User Data File Structure
UEL	Under Excitation Limiter

Introduction

This document complements the Compliance Processes (CP) included in the Grid Code providing additional description of the technical studies and testing set out within the Grid Code.

To achieve Operational Notification, the Generator, the company owning and operating a Power Park, 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 or specific parameters within a range indicated in the Grid Code. The total requirements placed on Generators are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

This particular edition of the guidance notes has been written for new distributed generation technologies (such as wind farms) referred to in the Grid Code as Power Parks. The guidance notes contents are based on experience gained from wind turbines but similar arrangements are expected to apply to other renewable technologies. A separate document exists for conventional synchronous 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.

Manufacturer’s Data & Performance Report

Manufacturers are concerned with protecting their innovations and technologies employed in Power Park Units which if shared could compromise their competitive advantage. In order to facilitate the market, the power industry has agreed that some information can be supplied direct to National Grid from Power Park Module manufacturers. The Grid Code (CP.10) explains National Grid may receive manufacturer information and Generators can reference itas part of their compliance demonstration. Appendix D of these guidance notes provides additional information for Power Park Unit manufacturers.

Generators should note that using registered manufacturer data does not guarantee Grid Code compliance for a Power Park Module, but does indicate that the Power Park Unit is capable of achieving Grid Code compliance in the appropriate area. Limited tests may be required to confirm that the performance of the Power Park Module aligns with the data held by National Grid in the Manufacturer’s Data & Performance Report Register. Any Generator wishing to use manufacturer data is advised to contact National Grid early in the compliance process to determine if the information held in the Register of Manufacturer’s Data & Performance Report is appropriate and sufficient in each case.

While Generators may not see the Manufacturer’s Data & Performance Report information, they must ensure that the correct reference is used as the same provisions will apply to this data as a normal Data Registration Code or a User Data File Structure submission. The Manufacturer's Data & Performance Report reference given by the Power Park Unit manufacturer will contain the following:

- manufacturer name;
- Power Park Unit type;
- date; and
- the relevant report version number.

The user should then reference the document in the appropriate place in the User Data File Structure. For example, in lieu of fault ride through studies, assuming suitable fault ride through information is available in a Manufacturers Data and Performance report, the user can enter the following sentence;

> "*This information has been submitted generically to National Grid and can be found in the National Grid Register of Manufacturer's Data & Performance Report under document reference "manufacturerX_10MWturbinetype1_22Aug08_reportver001*"

Compliance Process

The process for Generators to demonstrate compliance with the Grid Code and Bilateral Agreement is included in the Grid Code Compliance Processes (CP). In addition to the process and details of the documentation that is exchanged to control the process an appendix to the Compliance Processes includes the technical details of the simulation studies that a Generator should carry out. The Compliance Processes cross reference with other sections of the Grid Code, namely the Planning Code (PC), the Connection Conditions (CC) and Operating Code 5 (OC5).

The PC sets out the data and information that a Generator is required to submit prior to connection and then maintain during the lifetime of the power station. The format for submission of the majority of this information is set out in the Data Registration Code (DRC).

The CC set out the majority of the generic performance requirements that a Generator is required to meet with site specific variations laid out in the Bilateral Agreement.

The OC5 sets out the technical details of the tests which National Grid recommends to demonstrate compliance with the Grid Code.

Simulation Studies

The simulation studies described in the Compliance Processes (CP.A.2), and Power Park Unit type and site tests described in sections, provide indicative evidence that the requirements of the Grid Code have been met. However if the study requirements specified in the Grid Code are inappropriate to the technologies employed on a particular project the Generator should contact National Grid to discuss and agree an alternative program and success criteria.

Guidance Notes – Power Park Modules

In general, simulation studies are required where it is impractical to demonstrate capability through testing as the effects on other system Users would be unacceptable. The simulations must be based on the validated models supplied to National Grid in accordance with Grid Code Planning Code Appendix section 5.4.2 (PC.A.5.4.2).

Validated Models

The Generator is required to provide National Grid and the Transmission Owner with a model of their Power Park Module as detailed in PC.A.5.4.2 (a to h) of the Grid Code. The model data is to be provided in a block diagram format, complete with Laplace equations and all associated parameters for the site in question. 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 electrical system is to be provided as a single line diagram.

The model structure and complexity must be suitable for National Grid to integrate into their power system analysis software (currently DigSilent). As a general rule, time constants less than 10ms should be avoided. 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 interpretation.

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 be considered incorrect and not contractually compliant. National Grid will confirm model accuracy using its power system analysis software.

The model also needs to be suitable for integration into the power system analysis software used by the relevant Transmission Owner (if not National Grid). 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 at National Grid).

National Grid encourages developers to work with manufacturers to develop the use of standard models for each type of Power Park Unit. This information can be provided as a Manufacturers Data & Compliance Report and this will minimise the work needed by all parties to validate Power Park models at each new site.

It is the responsibility of the Generator to provide information as described in the Planning Code, which enables National Grid to model the National Electricity Transmission System.

Compliance Tests

General

Tests identified in OC5.A.3 of the Grid Code are designed to demonstrate, where possible, that the relevant provisions of the Grid Code and Bilateral Agreement have been met. However if the test requirements described in OC5.A.3 are at variance with the Bilateral Agreement or the test requirements are not relevant to the plant type, the Generator should contact National Grid to discuss and agree an alternative test program and success criteria.

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 OC5. The Generator is responsible for drafting test procedures for the power station as part of the compliance process prior to the issue of the Interim Operational Notification (ION). Grid Code OC5 and the appendices of these guidance notes provide outline test schedules which may assist the Generator with this activity.

National Grid may require further compliance tests or evidence to confirm site-specific technical requirements (in line with Bilateral Agreement) or to address compliance issues that are of particular concern. Additional compliance tests, if required, will be identified following National Grid’s review of submissions of User Data File Structure (UDFS).

The tests are carried out by the Generator, or by their agent, and not by National Grid. However, National Grid will witness some of the tests as indicated in OC5. Tests should be completed following the test procedures supplied in the UDFS prior to the issue of the ION unless otherwise agreed by National Grid.

The Generator should also provide suitable digital monitoring equipment to record all relevant test signals needed to verify the Power Park Module performance in parallel with National Grid recording equipment.

National Grid Data Recording Equipment

National Grid will provide a digital recording instrument on site during the tests witnessed by National Grid. A generic list of signals to be monitored during National Grid witnessed tests is tabulated in OC5.A.1.3. This will be used to monitor all plant signals at a sampling rates indicated in CC.6.2.2. The station should provide its own digital recording equipment to record the same plant variables. This will provide a back up to the test results should one of the recording instruments fail at the time of testing.

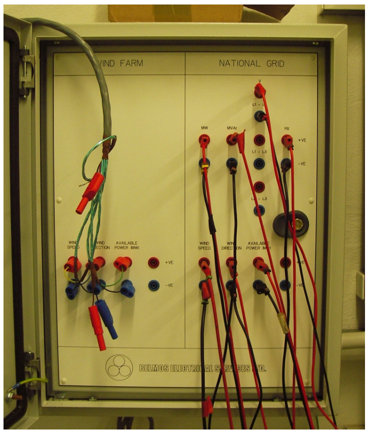
The station is responsible for providing the listed signals to the User's and National Grid's recording equipment. For National Grid purposes, the signals provided are required to be in the form of dc voltages within the range -10V to +10V (see CC.6.2.2). The input impedance of the National Grid equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.

The station should advise National Grid of the signals and scaling factors prior to the test day. A form of a typical test signal schedule is shown below:

Guidance Notes – Power Park Modules

Signal	Unit	Voltage Range	Signal Representation
Active Power Output	MW	0 to 8V	0 to Reg. Capacity
System Frequency	Hz	-8V to +8V	48.0Hz – 52Hz
List of other signals ….. …..			

It may be appropriate for National Grid to set up the recording equipment on the day prior to the test date. The station representatives are asked to ensure that a 230V AC power supply is available and that the signals are brought to robust terminals at a single sampling point. Examples of ideal connection points with BNC or 4mm banana plug connections are shown below.



The Power Park developer must inform National Grid if the signal ground (0V) is not solidly tied to earth or of any other potential problems.

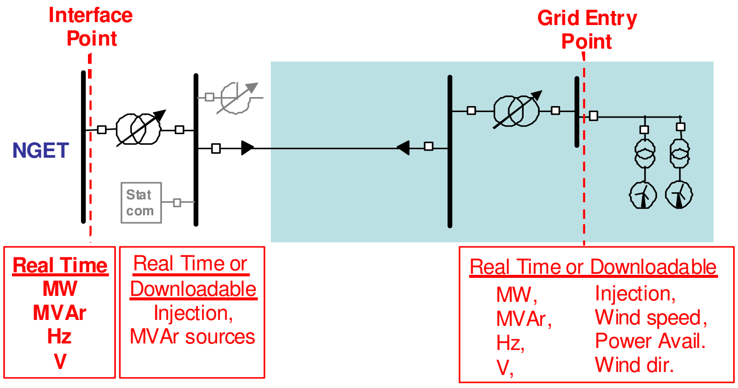
With Power Park Modules, where sometimes real time analogue signals cannot be outputted from the control scheme, the Grid Code OC5.A.1.3(a) allows for the basic signals to be supplied directly from transducers connected to CTs/VTs on the interface circuit. The transducer(s) should be permanently installed at the Users location to easily allow safe testing at any point in the future, and to avoid a requirement for recalibration of the CTs / VTs. All the signals should then be available from the Power Park control systems as a download once the testing has been completed as described in OC5.A.1.3(b) and (c).

The four basic signals are:

1) Total MW
2) Total MVAr
3) Point of connection line-line Voltage (HV) (kV)
4) System frequency (Hz)

For offshore Power Park Modules, the control and signals for the witnessing of all testing should be available at the onshore connection point to avoid the risks associated with offshore working. For offshore Power Park Modules the real time signals for witnessing tests are measured at the onshore Interface Point as illustrated in the following diagram and mentioned in OC5.A.1.3.2(iii).

Typical Signals for Offshore Wind Farm Witness Testing (OC5.A.1.3)



The National Grid Register of Manufacturer's Data & Performance Reports

Users may wish to reference data held in the National Grid Register of Manufacturer's Data & Performance Reports to help to complete various parts of the compliance process (see Section 3 of this document). This can be achieved by placing the manufacturer document reference in the appropriate place in the Data Registration Code or User Data File Structure. This reference should be obtained by the User from the Power Park Unit manufacturer. Please note that it is the responsibility of the User to ensure that the correct reference is submitted to National Grid.

Even though different Power Park Modules may be comprised of the same Power Park Unit type, differences in performance can result. Submitting a Register of Manufacturer's Data & Performance Report reference can therefore not be a guarantee of compliance, and the suitability of the reference should be discussed with National Grid as part of the normal compliance process.

Interim Operation

As there may be a considerable period between commissioning the first and last power Park Unit within a module, the Grid Code Compliance Processes (CP) provides two capacity restrictions during commissioning. These restrictions are managed by items included in the ION. The Generator is required to complete basic voltage control and frequency response tests and have the results approved by National Grid in order to have the capacity restrictions released.

Test Notification to Control Room

The Generator is responsible for notifying the 'National Grid Control Centre' of any tests to be carried out on their plant, which could have a material effect on the National Electricity Transmission System. The procedures for planning and co-ordinating all plant testing with the 'National Grid Control Centre is detailed in OC7.5 of the Grid Code (i.e. Procedure in Relation to Integral Equipment Tests). For further details relating to this procedure, refer to "Integral Equipment Tests - Guidance Notes" which can be found on National Grid's Internet site in Grid Code, Associated Documents.

The Generator should be aware that this interface with National Grid transmission planning will normally be available in week-day working hours only. As best practice the

Guidance Notes – Power Park Modules

Generator should advise the 'National Grid Control Centre' and in Scotland the relevant Transmission Owner, or Distribution Network Operator (if embedded) of the times and nature of the proposed tests at the earliest stage possible. If there is insufficient notice or information provided by the Generator, then the proposed testing may not be allowed to proceed.

Compliance Testing with Limited Power Source Availability

Many of the compliance tests require operation at a significant proportion of Rated MW. An Interim Operational Notification extension may be provided to allow operation until sufficient resource is available to complete the compliance tests at a suitable level of generation. In some cases the compliance tests may be approved at reduced capacity provided National Grid are satisfied that the Power Park Module capability is sufficiently supported by generic type validation tests and site design data.

Compliance Testing of Power Stations Comprised of Identical Power Park Modules

Where a Power Station is comprised of two or more identical Power Park Modules, National Grid may allow reduced compliance testing on the remaining Power Park Module(s) provided that the first Power Park Modules successfully completed the full testing.

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 User Data File Structure content, 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 Park Module and Power Park Units 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 (see below)	Type, description, settings and time delays

Islanding Protection

If anti-islanding protection is required, an inter-tripping scheme is recommended. However, 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.

Power Quality Requirements

For Power Parks that are to be connected to the National Electricity Transmission System, the harmonic distortion and voltage fluctuation (flicker) limits are set out in accordance with the Grid Code. The Transmission Owner is required to meet the relevant terms of the Grid Code.

With respect to harmonics, the Grid Code CC.6.1.5(a) requires that the Electromagnetic Compatibility Levels for harmonic distortion on the Transmission System from all non-linear sources under both planned outage and fault outage conditions, (unless abnormal conditions prevail) shall comply with the compatibility levels given in Appendix A of Engineering Recommendation G5/4. The Grid Code further requires that the planning criteria contained within Engineering Recommendation G5/4 be applied for the connection of non-linear sources to the Transmission System, which result in harmonic limits being specified for these sources in the relevant Bilateral Agreement.

With respect to voltage fluctuations, it is also a requirement of the Grid Code that voltage fluctuations are kept within the levels given in Grid Code CC.6.1.7 and/or Table 1 of Engineering Recommendation P28 and therefore limits on voltage fluctuations are also specified in the relevant Bilateral Agreement. The Power Park Developer will be required to comply with the harmonic and voltage fluctuation limits specified in the Bilateral Agreement. The Transmission System or Distribution Network Operator will monitor compliance with these limits.

Development schemes with non-linear element(s) are assessed by the Transmission Owner for their expected impact on the harmonic distortion and voltage fluctuation levels. For harmonic voltage distortion, the process detailed in Stage 3 of Engineering Recommendation G5/4 is applied. For the voltage fluctuation, the principles outlined in Engineering Recommendation P28 are used, with contribution from the Power Park being calculated according to the International Electrotechnical Commission standard IEC61400-21.

Specific information required for the assessment of harmonic voltage distortion and voltage fluctuation is detailed in Grid Code DRC.6.1.1. Any component design parameters for planned reactive compensation for the Power Park as detailed in Grid Code PC.A.6.4.2 should also be included giving due attention to tuned components.

For Power Parks that are to be connected to Distribution Systems, Distribution Network Operators may undertake similar assessments to comply with the requirements of the Distribution Code in terms of harmonic distortion and voltage fluctuation.

Appendix A - Reactive Capability

Summary of Requirements

The Reactive Capability requirements for a Power Park Module are specified in Grid Code CC.6.3.2.

In summary, the first part of the requirement is for the Power Park Module to be capable of operating with no reactive power transfer to the public power system (with a tolerance) from zero power output to full output. The second part of the requirement is for the Power Park Module to be capable of operating with a range of reactive power outputs when producing more than 20% real power. This reactive power capability at the connection point (or HV side of the connection transformer for a "Transmission" connection site in Scotland) is illustrated in the Figure 1 in CC.6.3.2.

Below 20% real power output, the Power Park Module may continue to modulate reactive power transfer under voltage control or switch to zero reactive power transfer. If there is a switch to zero reactive power transfer, the Grid Code requires that there is a smooth transition between Voltage Control at active power levels greater than 20% and reactive power control at active power levels less than 20%.

Further clauses of Grid Code CC.6.3.2 include some variations to the Reactive Capability requirements relating to older Power Park Modules completed before 1 January 2006.

Grid Code CC.6.3.4 states that the reactive power capability must be fully available at all system voltages in the range ±5% of nominal. Generators connected at 33kV or below, are only required to meet the relaxed voltage/reactive capability envelope shown by CC.6.3.4 Figure 4. This relaxation recognises that the power park developer does not have control of a transformer tapchanger to control voltages within his network. The CC.6.3.4 capability is not normally tested but is demonstrated by simulation.

In the event that during system incidents (i.e. the voltage is ≤95% or ≥105%) plant should deliver the maximum (lagging or leading respectively) reactive power possible, whilst remaining within its design limits.

Contractual Opportunities Relating to Reactive Services

For some technologies there is an opportunity to provide an optional reactive service (beyond the basic mandatory reactive service) covering the period when the renewable energy source is not available (e.g. when a wind turbine has no wind). Developers interested in providing such a service should take the opportunity of reactive capability testing to demonstrate this zero power reactive capability. The delivery of reactive power would be expected to be dynamic, i.e. responding to changes to system voltage in the same manner as normal operation.

Reactive Capability Compliance Tests

Grid Code OC5.A.3.4 describes the Reactive Capability testing. The required tests should demonstrate the maximum capability of the Power Park Module beyond the corners of the envelope shown in Grid Code CC.6.3.2 Figure 1. Given the steady state nature of the Reactive Capability requirements implying that reactive output can be maintained indefinitely, the tests are carried out over a longer period than other compliance tests.

In order that the Generator has maximum opportunity to take advantage of periods of high wind and recognising the steady state nature of these tests, the Reactive Capability test is not usually witnessed by a National Grid compliance engineer.

In order to demonstrate that a Power Park Module can satisfy the reactive capability requirements it is necessary to perform reactive capability tests as set out in OC5.A.3.4.5. An example of a corresponding test schedule is shown below.

Test No	Step	Description	Notes
1		Plant in Voltage Control Increase Active power output to maximum Target Voltage selected to generate a maximum continuous lagging Reactive Power for 60 minutes.	
2		Increase Active power output to maximum Target Voltage selected to generate a maximum continuous leading Reactive Power for 60 minutes.	
3		Reduce active power output to 50% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes.	
4		Reduce active power output to 20% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes.	
5		Reduce active power output to 20% Rated MW Target Voltage selected to generate a maximum continuous lagging Reactive Power for 5 minutes.	
6 (Note1)		Increase Active power output to 25% Rated MW Target Voltage selected to generate a value of Lagging Reactive Power greater than 5% Rated MW Reduce Power Park Output to <20% as a ramp over 10 seconds Hold Power Park Output <20% for 5 minutes	
7 (Note2)		Reduce active power output to 0 MW Target Voltage selected to generate a max Lagging Reactive Power maximum continuous lagging Reactive Power for 5 minutes.	
8 (Note2)		Reduce active power output to 0 MW Target Voltage selected to generate maximum continuous leading Reactive Power for 5 minutes.	

Notes

1. If the Power Park Module does not provide voltage control below 20% active power output then test 6 should be carried out to demonstrate smooth transition to within the required reactive power envelope.
2. If the Power Park Module provides voltage control down to zero active power output then tests 7 and 8 should be performed

Reactive Capability tests are not normally witnessed by National Grid so where a Generator is recording the tests the following test record sheet is suggested.

RECORD OF REACTIVE POWER MONITORING RESULTS

POWER PARK MODULE ....

Date of Test .... Approximate Wind Conditions ....mps

Power Station Control Engineer .... NGET Control Engineer...........................

Test Data Recorded by................................. for ………………………….……..(Company)

Power Park Module	Time	MW At Connection Point	MVAr Lead/Lag At Connection Point	Voltage At Connection Point	Tap* Position (if known)	HV* Voltage (if known)

* Scottish Connections where Connection Transformer owned by Transmission Owner

OBSERVATIONS / REMARKS

Appendix B - Voltage Control and PSS Testing

Summary of 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(c) requires provision of a continuously acting automatic voltage control which is stable at all operating points. The point of voltage control is the Grid Entry Point or User System Entry Point if Embedded.

Grid Code CC Appendix 7 requires:

- CC.A.7.2.2.2 The voltage set point should be adjustable over a range of ±5% of nominal with a resolution of better than 0.25%.
- CC.A.7.2.2.3 The voltage control system should have a reactive slope characteristic which must be adjustable over a range of 2 to 7% with a resolution of 0.5%. The initial setting should be 4%.
- CC.A.7.2.3.1 The speed of response to a step change should be sufficient to deliver 90% of the reactive capability within 1 second with any oscillations damped out to less than 5% peak to peak within a further 1 second.
- CC.A.7.2.2.5 The control system should deliver any reactive power output correction due from the voltage operating point deviating from the slope characteristic within 5 seconds.
- CC.A.7.2.2.6 The Power Park Module must continue to provide voltage control through reactive power modulation within the designed capability limits over the full connection point voltage range ±10% (CC.6.1.4) however the full reactive capability (CC.6.3.2) is only required to be delivered for voltages within ±5% of nominal in line with CC6.3.2 and CC.A.7.2.2 (b) or Figure 4 of CC.6.3.4 if applicable.
- Grid Code Figure CC.A.7.2.2(b) Illustrates the operational envelope required.

The Generator must provide National Grid with a transfer block diagram illustrating the Power Park Module voltage control scheme 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 File Structure (UDFS). The information will enable National Grid to review the suitability of the proposed test programme to demonstrate compliance with the Grid Code.

Target Voltage and Slope

The National Grid Control Centre issues voltage control instructions to all Balancing Market participants. For Power Park Modules the usual instruction is to alter Target Voltage set point and should be carried out in the usual 2 minutes required for Ancillary Service instructions. The slope may also be varied by control instruction but the Generator has up to a week to complete the change. Slope is usually expected to be set at 4%. The procedures for Voltage Control instructions are included in Grid Code Balancing Code (BC) 2.

Delivery of Reactive Capability Beyond ±5% Voltage

The Grid Code requires a Reactive Capability equivalent to ±0.95 power factor usually at the Grid Entry Point or User System Entry Point if Embedded. For older wind farms, variations from this will be stated in the Bilateral Agreement. Grid Code CC.6.3.4 requires that the full Reactive Capability is capable of being delivered for voltages at the Grid Entry Point within ±5% of nominal.

Outside this range the Power Park Module must be capable of continuing to contribute to voltage control by delivering Reactive Power. However, the level of reactive power delivered may be limited by the design of the plant and apparatus. There is no low or high limit on this obligation, plant must continue to provide maximum reactive power within its design limits.

Transient Response

The Grid Code CC.A.7.2.3.1 sets out a number of criteria for acceptable transient voltage response. The two Figures below illustrate responses from two different control philosophies that would be considered as meeting the Grid Code.

Figure B.1 illustrates a control scheme which employs a constant speed of response.

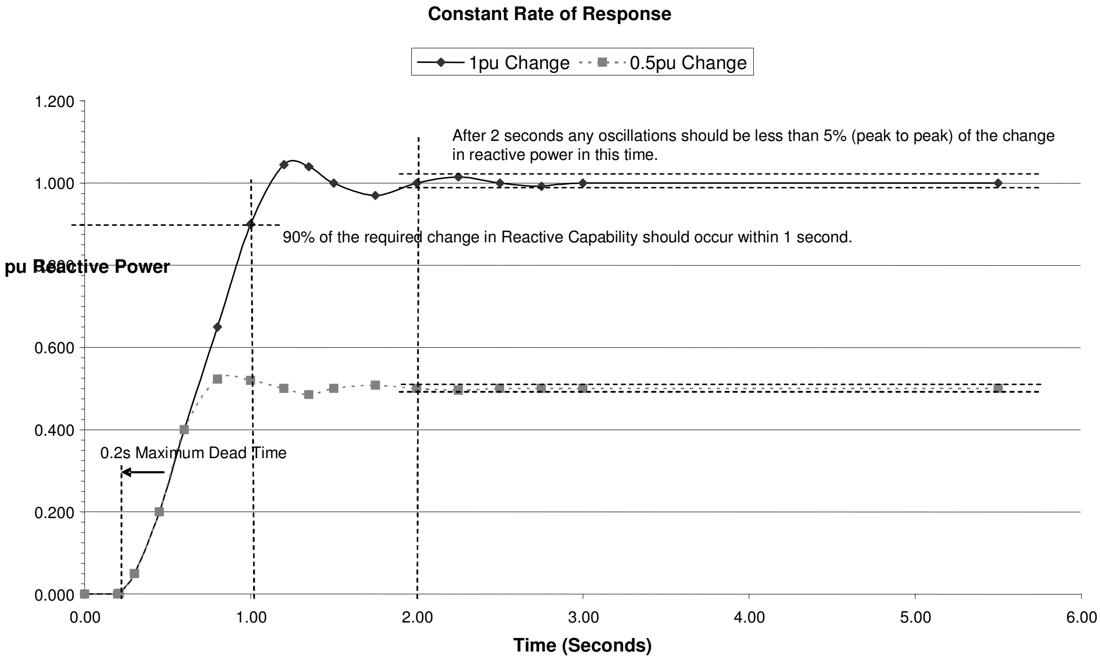


Figure B.1

Figure B.2 shows a control scheme which varies the rate of response proportional to the size of the step change.

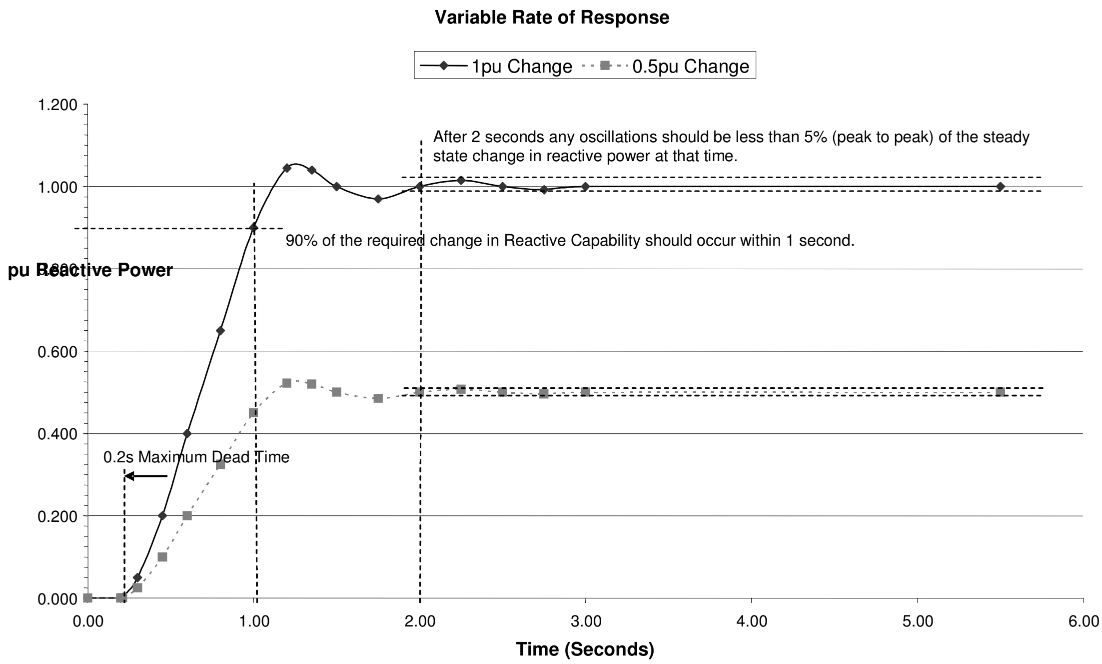


Figure B.2

Both Figures B.1 and B.2 are examples of acceptable responses. Both graphs show the response to two steps, one to initiate a 1pu and the other a 0.5pu change in reactive capability. The graphs show how a variable and constant rate of change both can allow the system to achieve the objective. In both cases the dead time is less than 200ms, 90% of the reactive capability (i.e. 90% of 0.95 power factor at full load or 32.9% MVAr as measured as a proportion of rated power at any other load) is achieved in 1 second and the system settles with a maximum oscillation of 5% peak to peak, in reactive power within 2 seconds.

Note: The Grid Code states that the reactive response to a change should be "linearly increasing". For technologies where this may not be appropriate (e.g. capacitor switching), provided the performance is equal to or faster than shown above it will be acceptable.

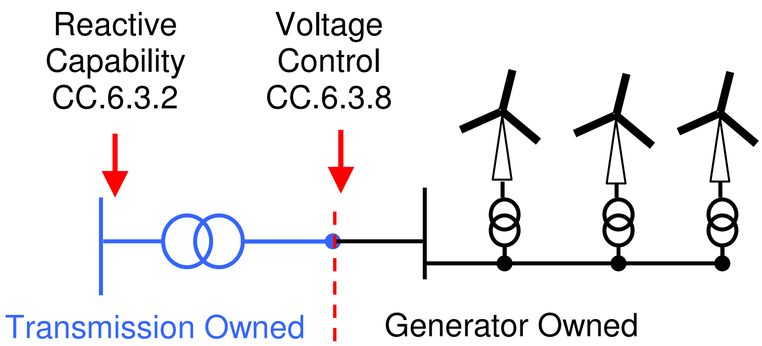
Variations in Voltage Control Requirements

The Grid Code is continually reviewed by National Grid and all Authorised Electricity Operators resulting in a document which is regularly updated. Changes in technical requirements that are considered material to Users are often related to plant Completion Dates. The aim of which is to prevent the need to retrofit older plant with new equipment.

As a result, Power Park Modules in Scotland with a completion date before the 1st of January 2006 the point of Voltage Control may be at the Power Park Unit terminals and appropriate intermediate bus bar or connection point as defined in the Bilateral Agreement.

Guidance Notes – Power Park Modules

For "Transmission Connected" Power Park Modules in Scotland the Grid Code specifies the Mvar requirement at the HV side of the 33/132 kV or 33/275 kV or 33/400 kV transformer (CC.6.3.2 (c)) at the connection site. The requirement is 0.95 lead to 0.95 lag at this point. However since the Grid Transformer always consumes Mvars the Mvar requirement is not symmetrical at the LV (33 kV) connection point where the ownership boundary is. CC.A.7.2.2.4 refer to this as the modified values of Qmax and Qmin. The Grid Code (CC.6.3.8) specifies that the voltage control is at the Point of Connection.

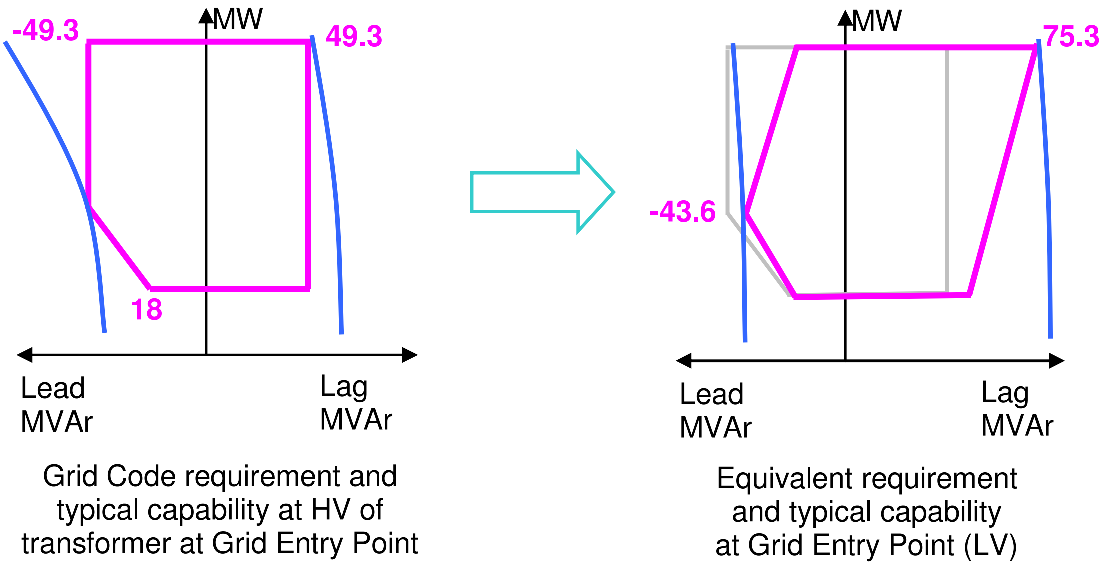


The following example illustrates derivation of the reactive capability at the 33 kV point for a 151MW Power Park Module with a maximum capability of 150 MW the 0.95 power factor corresponds to 49.3 Mvars.

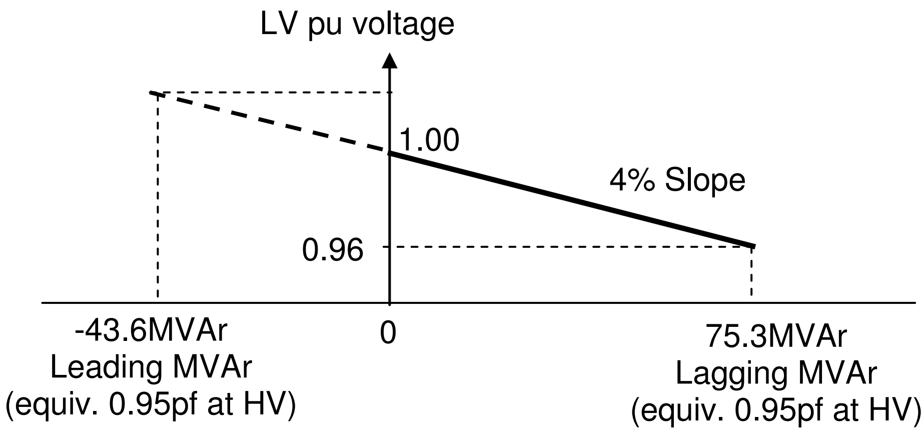
The maximum lagging capability requirement at the LV will be when the active power generation is at 100% as reactive absorption in transformer is greatest.

The maximum leading capability will be at 50% generation due to the shape of the requirement characteristic below 50% active power.

Power factor at HV	Mvars at HV (132 kV)	LV voltage(pu)	Mvars at LV (33 kV)			Mvar loss in Transformer
			150MW	75MW	30MW	
0.95 lag (export)	49.3	0.95 pu	**75.3**		52.7	26.1
unity	0	1 pu	19.1			19.1
0.95 lead (import)	-49.3	1.05 pu	-31.5	**-43.6**		17.7
12% (18 Mvar)					-17.2	



It can be seen that the Qmax and Qmin at the 33kV busbar are not symmetrical so the slope is set for the capacitive capability and is then continued for the inductive range. This is the same philosophy for a typical Static Var Compensator. When the slope is 4%, for a voltage change of 0.04 pu, the Mvar at LV should change from 0 Mvar to 75.3 Mvar at the LV. This slope line should be then extended in the opposite direction only as far as to provide -43.6 Mvar, i.e. the maximum leading capability. However the voltage change needed to produce –43.6 Mvar would be a voltage increase less than 0.04 pu. It should be noted that when the reactive power at the LV is 0 Mvar, at rated MW, there will be an intake from the transmission system of about 19 Mvars.



Compliance Test Description

The voltage control tests for a Power Park Module are set out in Grid Code OC5.A.3.5. As described testing should be by tapping of an upstream grid transformer and also by injection to the control system reference.

Where steps can be initiated using network tap changers, the Generator will need to coordinate with the host Transmission or Distribution Network Operator. Consideration should also be given to switching the associated tap changer Automatic Voltage Control (AVC) from auto to manual for the duration of the test.

Suggested Power Park Module Voltage Control Test Procedure

The Module Test should be done when all of the Power Park Units and any reactive compensation units are in service. Wind conditions (or Tidal etc.) should be such to allow power production from the Module of at least 65% Registered Capacity.

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

Test	Step No	Description of Injection	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
V1		• Record steady state for 10 seconds • Inject +1% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V2		• Record steady state for 10 seconds • Inject -1% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V3		• Record steady state for 10 seconds • Inject +2% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V4		• Record steady state for 10 seconds • Inject -2% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	

Test	Step No	Description of Tapchange	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
T1	1	• Record steady state for 10 seconds • Tap up 1 position on external upstream tap changer • Hold for at least 10 seconds	
	2	• Tap up 1 position on external upstream tap changer i.e. up 2 positions from starting position. • Hold for at least 10 seconds	
	3	• Tap down 1 position on external upstream tap changer i.e. up 1 positions from starting position. • Hold for at least 10 seconds	
	4	• Tap down 1 position on external upstream tap changer i.e. at starting position. • Hold for at least 10 seconds	

	5	• Tap down 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	
	6	• Tap down 1 position on external upstream tap changer i.e. down 2 positions from starting position. • Hold for at least 10 seconds	
	7	• Tap up 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	
	8	• Tap up 1 position on external upstream tap changer i.e. return to starting position. • Hold for at least 10 seconds	

Where the voltage control system includes discretely switched shunt capacitors/reactors to provide part of the reactive capability the test program should demonstrate the performance when these are switched.

Test	Step No	Description of Injection	Notes
		Adjust voltage setpoint to a suitable operating point below switching threshold for shunt device.	
V5	 9 10 11	• Record steady state for 10 seconds • Inject a step to the Power Park Module Voltage Reference of sufficient size and polarity to switch in shunt device. • Hold for at least 10 seconds • Remove injection with a step of sufficient size to switch out the switched device • Repeat step 9 immediately (with minimum delay)	

Where switched devices are normally rotated, devices not required for the particular test should isolated to prevent their involvement.

Demonstration of Slope Characteristic

The Power Park Module voltage control system is required to follow a steady state slope characteristic. This should be demonstrated by recording voltage at the controlled busbar (usually the Grid Entry Point or User System Entry Point if Embedded) and the reactive power output at the same point over several hours. Plotting the values of Voltage against Reactive Power output should demonstrate the slope characteristic.

Additional Power System Stabiliser Testing

Additional tests are required if a Power System Stabiliser is fitted. Although the fitting of Power System Stabilisers on non-synchronous plant is a rarity, one may be provided within the control system by a manufacturer or National Grid may specify the requirement in the Bilateral Agreement. The testing process outlined in this section is based largely on that employed on synchronous plant, which is believed to be comparable. However, Generators should anticipate the possibility that an alternative testing regime may be developed in discussion with National Grid.

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 along with the proposed test procedure in the User Data File Structure (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 on a module basis. 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 Power Park Module 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.

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

PSS testing is additional to the Module Voltage Control Tests.

Suggested Power Park Module PSS Test Procedure

The PSS Test should be done when at all of the Power Park Units and any reactive compensation units are in service. Wind conditions should be such to allow power production from the Module of at least 65% Registered Capacity.

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

Step No	Test	Injection	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor PSS Not in Service	
1 2 3	1	• Record steady state for 10 seconds • Inject +1% step to Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module Voltage Reference to nominal and hold for at least 10 seconds	
4 5	2	• Record steady state for 10 seconds • Inject +2% step to Power Park Module Voltage Reference	

6		and hold for at least 10 seconds • Remove step returning Power Park Module 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 Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module 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 Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module 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	
		Repeat Module Voltage Control Tests with PSS in service.	

Appendix C - Frequency Control

Summary of Requirements

The National Electricity Transmission System is an island network with no AC connections to mainland Europe. In order to manage the system frequency within the normal operating range 49.5 to 50.5Hz (CC.6.1.2) National Grid requires generating units and power park modules to be able to continuously modulate their output in relation to frequency across this range. In order to maintain a stable system frequency it is important that response from plant is achieved without undue delay.

The Grid Code sets out Frequency Control requirements in a number of separate places, notably the Glossary & Definitions (GD), the Connection Conditions (CC) and Balancing Code (BC) 3. This section summarises the key requirements.

The GD of the Grid Code defines Primary, Secondary and High frequency response including the requirement that the response is progressively delivered with increasing time.

CC.6.3.3 of the Grid Code specifies that the Power Park Module must be capable of maintaining a minimum level of active power (see Figure 2 of CC.6.3.3 (b)) in the frequency range 47Hz to 50.5Hz.

CC.6.3.7 of the Grid Code specifies the minimum frequency control capability, in particular the frequency control must be:

- Stable over the entire operating range from 47Hz to 52Hz.
- Able to contribute to controlling the frequency on an islanded network to below 52Hz.
- Capable of a frequency droop of between 3 and 5%.
- Capable of providing frequency control against a target set in the range of 49.9Hz and 50.1Hz.
- Have a frequency control dead band of less than ±0.015Hz.
- Capable of delivering a minimum level of frequency response.

Grid Code Figure CC.A.3.1 specifies a minimum requirement for frequency response of 10% of Registered Capacity achievable for Primary Secondary and High Frequency response. This minimum value is designed to ensure that plant provides a suitable contribution to maintain frequency correction when connected to the system and selected to Frequency Sensitive Mode (FSM) and response capability in excess of 10% is encouraged.

The speed of response is an important criterion and the Grid Code Figures CC.A.3.2 and CC.A.3.3 indicate typical responses from plant with no delay in response from the start of the frequency deviation. Practically there is a permissible deadband and National Grid accepts a delay of up to but not exceeding 2 seconds before measureable response is seen from a generating unit in response to a frequency deviation.

BC3 of the Grid Code specifies how plant should be operated and instructed to provide frequency response. The section also sets out the requirements on how all plant should respond to the system frequency rising above 50.4/50.5Hz, by progressively reducing output power.

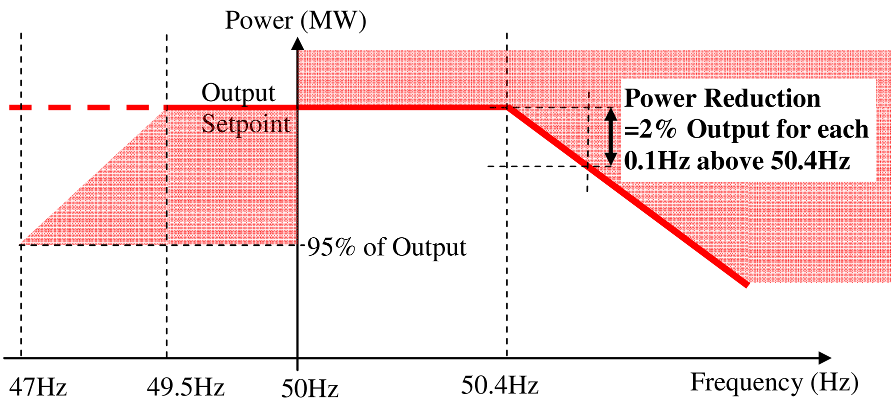
Details of the tests required for the preliminary and main governor response tests are provided in OC5.A.2.8 but additional guidance is provided in this Appendix including outline test procedures.

Modes of Frequency Control Operation

Balancing Code 3 (BC3) of the Grid Code defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode.

Limited Frequency Sensitive Mode is used when not instructed by National Grid to provide Frequency Response Services. In this mode the Power Park Module is not required to provide any increase in active power output if frequency reduces below 50Hz and is only required to maintain active power output in accordance with CC.6.3.3. However, the Power Park Module is required to respond to high frequencies above 50.4Hz beyond which the Module must reduce the active power output by a minimum of 2% of output for every 0.1Hz rise above 50.4Hz (see figure C1). Should this cause power output to be forced below Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

Power/Frequency Characteristic for Limited Frequency Sensitive Mode



Grid Code References | CC.6.3.3, BC.3.5.2 | BC.3.7.2

Figure C1 – Limited Frequency Sensitive Mode

Frequency Sensitive Mode is used when selected to provide frequency response services. In this mode the Power Park Module must adjust the active power output in response to any frequency change according to the agreed droop characteristic (between 3-5%). For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration. When system frequency exceeds 50.5Hz the requirements of Limited Frequency Sensitive Mode apply so that the Power Park Module must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz (see figure C2). Should this cause power the output to be forced below the Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect from the system after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

Power/Frequency Characteristic for Frequency Sensitive Mode

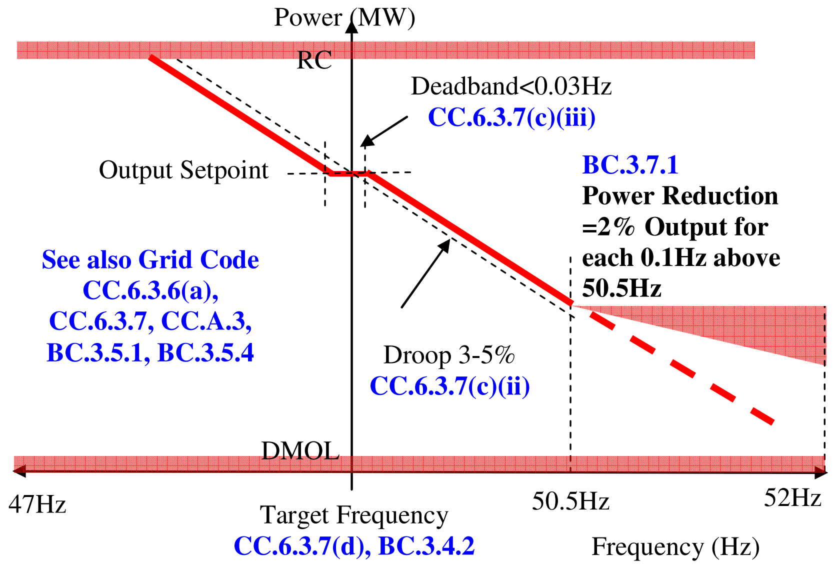


Figure C2 – Frequency Sensitive Mode

Target Frequency

All Balancing Market Units (BMUs), irrespective of the plant type (conventional, wind, thermal or CCGT, directly Grid Connected or Embedded), are 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 National Grid Control Centre instructs all Active Balancing Market Unit to operate with the same Target Frequency, normally 50.00 Hz. In order to adjust electric clock time the System Operator may instruct Target Frequency settings of 49.95Hz or 50.05Hz. However, under exceptional circumstances, the instructed settings could be outside this range. The Grid Code requires a minimum setting range from 49.90Hz to 50.10Hz.

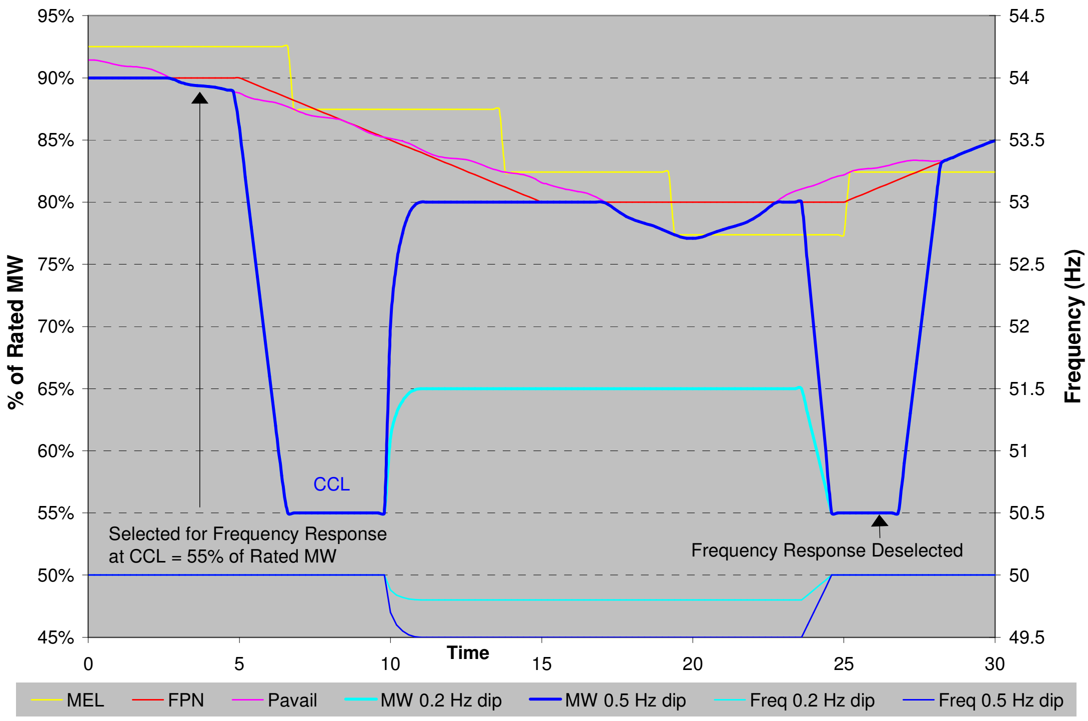
De-load Instructions

System balancing is a separate issue to that of frequency response. A de-load instruction is to a fixed MW value rather than a delta MW value from available power. This removes the majority of the uncertainty associated with the variability of the wind at times when the amount of generation needs to be accurately controlled to allow the system to be safely and securely balanced. This is of course at the expense of a variable low frequency response volume.

Frequency Response from an Intermittent Power Source

Clearly the low frequency response available from a Power Park Module using an Intermittent Power Source is ultimately limited by the available power (referred to as 'Pavail'). It is expected that the low frequency response will be maintained for reducing levels of Power Source unless the 'Pavail' limits the possible response. Figure C3 below illustrates the expected frequency response when 'Pavail' reduces and encroaches upon the available response.

Figure C3 Expected Frequency Response with Reducing Intermittent Power Source



Notes:

The Maximum Export Limit (MEL), is declared to National Grid as a Balancing Mechanism parameter effectively equivalent to 'Pavail' which should be updated whenever the 'Pavail' changes by more than 5% or 5MW. The Final Physical Notification (FPN) is the generated power profile submitted to National Grid for a ½ hour period before gate closure. Gate closure is one hour ahead of real time. The Capped Committed Level (CCL) is the power level at which a Power Park Module operates when selected for frequency response.

Guidance Notes – Power Park Modules

More detailed guidance for manufacturers on how the control system should respond to variations in power setpoint, system frequency and the intermittent power source is included in Appendix E.

Summary of Steady State Load Accuracy Requirements

Grid Code CC.6.3.9 requires a Power Park Module to be able to control output to a target with an accuracy specified as a standard deviation. With an intermittent power source this requirement applies when operating at power levels below the Maximum Export Level (MEL) which should reflect the availability of the power source.

To demonstrate compliance, the Power Park Module should self dispatch for 30 minutes at a load significantly below the Maximum Export Level (MEL). The active power output and power available should be recorded with a sampling rate not less than once per minute.

Compliance Testing Requirements

The main objectives of the frequency 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 as a measured set of plant response values that will verify the response matrices for the Mandatory Services Agreement.

In order to verify the plant behaviour it is essential that the module is tested in normal operating modes. A frequency disturbance can be simulated by injecting the required frequency variation signals to the frequency reference/feedback summing junction. The results obtained from reducing frequency ramps will be used to verify primary and secondary frequency response. Similarly the results obtained from increasing ramps will be used to verify the high frequency response. Robust and stable response to islanding events can be demonstrated by injecting large and rapid frequency disturbances and observing the response. The recommended tests are shown in Grid Code OC5.A.3.6 Figures 1 and 2.

Typical Frequency Control Test Injection

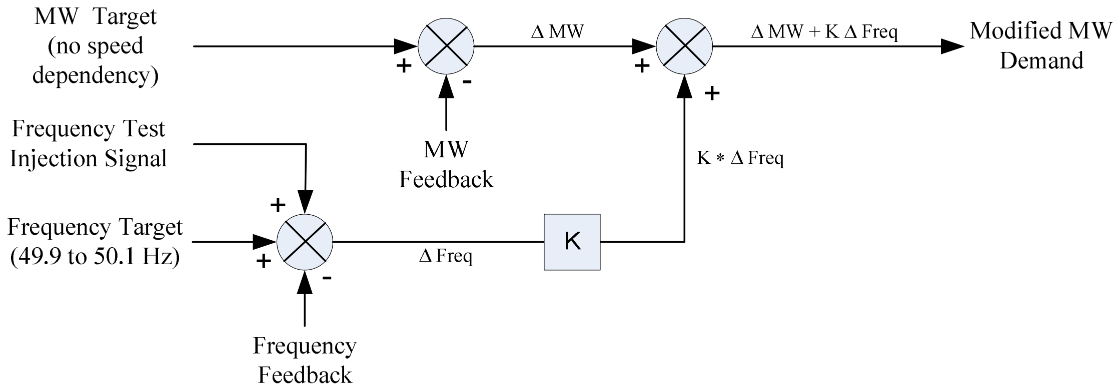
A frequency injection signal is needed to undertake all frequency related capability tests. Ideally the injected signal will be directly added into the raw frequency feedback as shown in the diagram below. If the Power Park Module frequency control strategy incorporates independent local frequency control at each Power Park Unit then the Generator must identify and implement a method to simultaneously change all relevant frequency control set points or feedback signals to replicate a network frequency change.

Ideally the signal will be software programmable with start/stop initiation via local or remote software interfaces or local digital inputs. Alternatively the signals should be a ±10V analogue input where 1 volt represents 0.2 Hz frequency change.

Guidance Notes – Power Park Modules

The above signals should be available at all control nodes within the Power Park controller network, so that if appropriate and applicable, injection can take place on a single Power Park Unit or the central controller.

Figure C4 Typical Frequency Test Injection Scheme



Power Level for Frequency Control Compliance Testing

Power Park Modules using an Intermittent Power Source can not always provide the Registered Capacity (RC) indicated to National Grid by declaring a lower Maximum Export Limit (MEL). MEL is a dynamic quantity based on the best estimate of available power. MEL can be constrained for many other reasons but for the purposes of this test it should only be constrained as a function of the available power source. Similarly, Stable Export Limit (SEL) is the minimum level that the Power Park Module can provide without tripping under normal Intermittent Power Source variation.

In principle, the maximum capacity available for low frequency response is determined by the 'deload' level from MEL. It is assumed that the low frequency response obtained from the 'deload' points tested above will not be substantially different when the MEL is at other values below RC provided the equivalent 'deload' from MEL is used (i.e. 70% RC would be undertaken at a load point of MEL minus 30% of RC). If this is not the case the Generator must inform National Grid and further tests may be required. Similarly the high frequency response should be similar at all MEL levels unless the response was to encroach upon the SEL.

OC5.A.3.6 sets out the minimum power output and Power Park Unit availability for testing to be carried out. However, National Grid reserves the right to request a repeat of the tests at up to 100% of RC if the response is shown to be non linear or monitoring of frequency response delivery by National Grid shows deviations from the submitted frequency response data table.

Preliminary Limited Frequency Sensitive Mode Testing

With large multi-module power stations there may be a considerable delay before final frequency response testing can be carried out. To control the risk to the system during this period Grid Code OC5.A.3.3.1 requires two tests in Limited Frequency Sensitive mode to be completed.

Preliminary Frequency Response Testing

Past experience has demonstrated that significant delays can occur during testing because of problems associated with the frequency controller setup 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 frequency controller are shown in Figure C4. 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 Power Park or site contractor. A preliminary test is therefore required with details given in Grid Code OC5.A.3.6.4 and illustrated 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 50.00 Hz.

With the plant running at a level approximately half way between full maximum output and Designed Minimum Operating Level, the following frequency injections should be applied.

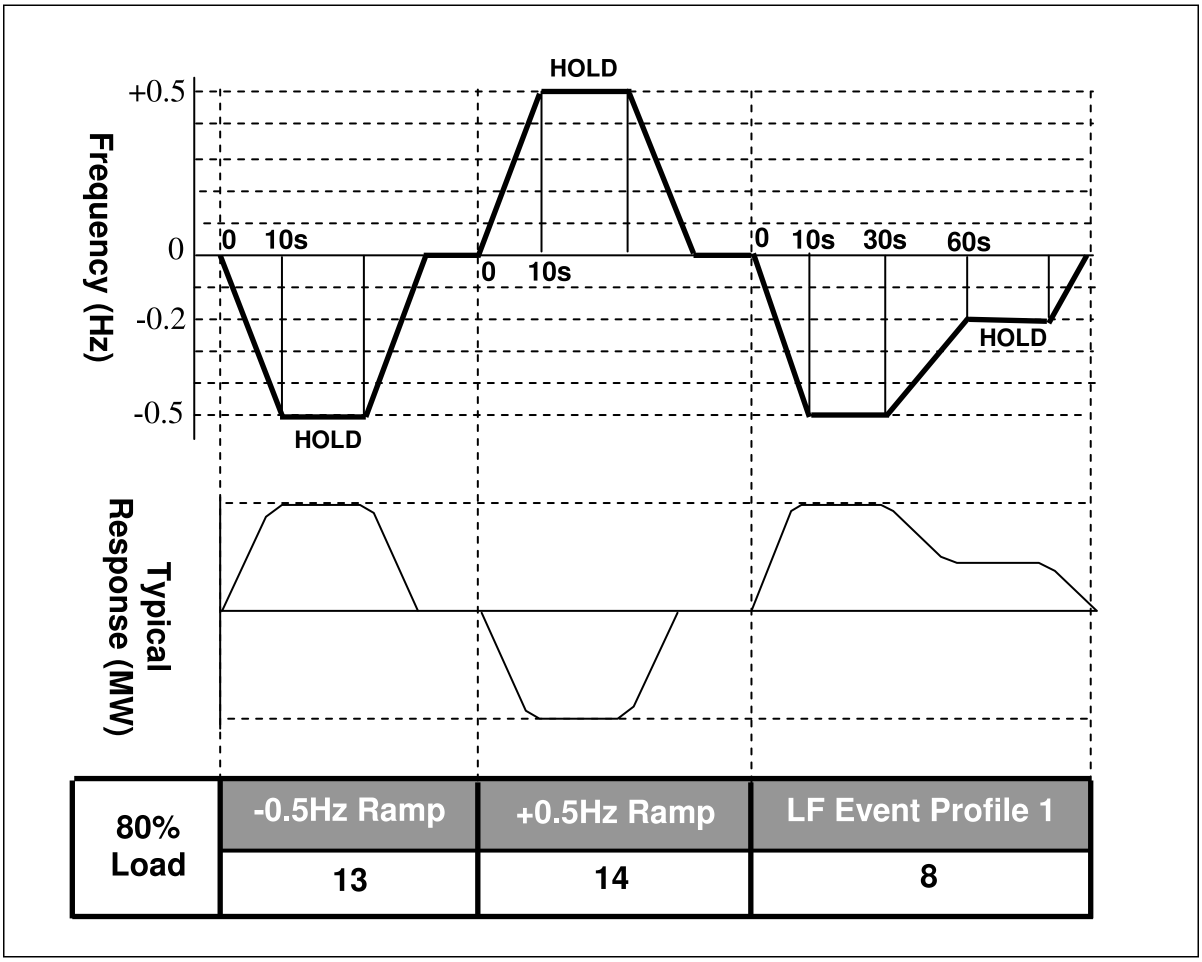


Figure C4 – Preliminary Frequency Response Tests

The recorded results (e.g. Freq. injected, MW, Pavail, wind speed and control signals) should be sampled at a minimum rate of 0.1 Hz to allow National Grid to assess the plant performance from the initial transients (seconds) to the final steady state conditions (which may typically take 2-3 minutes depending on the plant design). The number of turbines in service should also be stated.

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

National Grid Witnessed Frequency Response Testing Sequence

Grid Code OC5.A.3.6. Figure 1 and Figure 2 give 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 0 as an example.

1. **Establish Maximum Plant Capacity as Loading Point MLP6**
(a) Switch power park controller 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 power park controller (i.e. Tests 1-4 in OC5.A.3.6Figure 1) and record plant responses.
(c) Conduct test BC1 – BC4 as shown in OC5.A.3.6 Figure 2 to establish the deloading capability as could occur under system islanding or system split conditions.

3. **Response Tests at Loading Point MLP5 (0.90 RC)**
(a) Operate the plant at MLP5.
(b) Conduct tests 5-7 as shown in OC5.A.3.6 Figure 1 and record plant responses.
(c) Conduct test A as shown in OC5.A.3.6 Figure 2 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 OC5.A.3.6 Figure 1 and record plant responses.
(c) Conduct tests D - I as shown in OC5.A.3.6 Figure 2 to establish the power park controller, and step response characteristics for power park controller modelling purposes.
(d) Conduct test J as shown in Figure 2 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 (DMOL+20%)**
(a) Operate the plant at MLP3.
(b) Conduct tests 15 to 17 as shown in OC5.A.3.6 Figure 1 and record plant responses.

6. **Response Tests at Load Point MLP2 (DMOL+10%)**

(a) Operate the plant at MG.

(b) Conduct tests 18 - 22 as shown in OC5.A.3.6 Figure 1 and record plant responses.

7. **Response Tests at Designed Minimum Operating Level MLP1 (DMOL)**

(a) Operate the plant at DMOL.

(b) Conduct tests 23 - 26 as shown in OC5.A.3.6 Figure 1 and record plant responses.

(c) Conduct test K as shown in OC5.A.3.6 Figure 2 to establish the step response characteristics for power park controller modelling purposes.

Generic Frequency Response Test Procedure

Since the governor response tests described above are to be arranged and conducted by the Generator, it is their responsibility to propose a test programme to suit their site specific requirements. A typical example of the test procedure based on OC5.A.3.6 Figures 1 and 2 is given below. This procedure is required to be submitted to National Grid for approval before an ION is issued.

Initial Checks on Maximum Plant Capability at MLP6, Plant in LFSM	
Step	**Actions**
1	Record plant MLP 6 condition including levels for module MW output, ambient wind speed, and direction.
2	Change power park controller to manual and increase output power demand to maximum.
3	Record plant conditions when plant is Stabilised.
4	Reset power park controller 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	1	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.10Hz	
6		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.10Hz	
7	2	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise	-0.20Hz	
8		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.20Hz	
9	3	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.20Hz	
10		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-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 +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+2.0 Hz * -2.0 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 • Hold until conditions stabilise at MLP 6	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.1
See Note 1	L	**Plant in FSM** • Record normal system variation in frequency and active power of the generating unit over at least 10 minutes. Load setpoint at maximum.	No injection	Check for live frequency measurement
Switch to Limited Frequency Sensitive Mode				
17 18	BC3	**Plant in LFSM** • Inject +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+2.0 Hz -2.0 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

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below Designed Minimum Operating Level in which case an appropriate injection should be calculated in accordance with the following:
For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. Calculation of the injected step should be as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	20%
Frequency Controller Droop	4%
Frequency to be injected = (0.65-0.20) x 0.04 x 50 =	0.9Hz

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	14	• Inject 0.50Hz frequency rise over 10 sec	+0.50Hz	

44		• Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-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
See Note 1	M	• Record normal system variation in frequency and active power of the generating unit over at least 10 minutes	No injection	
See Note 2	N	**<u>Plant in LFSM</u>** • Record normal system variation in frequency and active power of the generating unit over at least 10 minutes Switch plant to Frequency Sensitive Mode	No injection	

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	16	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.50Hz	

63		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-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

Tests L and M in OC5.A.3.6. Figure 2 should be conducted if the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests simply consist of monitoring the Power Park Module in Frequency Sensitive Mode during normal system frequency variations without applying any injection.

Test N in figure 2 should be conducted in all cases. All three tests should be conducted for a period of at least 10 minutes.

Control Requirements that may be witnessed

During attendance on site for witness testing of frequency response, National Grid may request that the Generator alters the Target Frequency setpoint from the Generators Control Room as an indication of controllability. This may be combined with tests M in OC5.A.3.6

Appendix D - Power Park Unit Performance Registration

Scope

This Appendix is intended to provide guidance for Power Park Unit Manufacturers rather than Generators on the direct submission of information and data to National Grid to assist in the demonstration of compliance.

Generic Power Park Unit Type Validation

Power Park Modules generally comprise of a large number of identical Power Park Units. Within manufacturing tolerances, the performance of a specific Power Park Unit type is normally reasonably constant from unit to unit and at whichever site they are installed. It is therefore possible to register various aspects of this performance and the associated data once, and then reference this data for some or all of the sites which use this particular type of equipment. The Grid Code recognises this by the provision of Manufacturer's Data and Performance Reports in CP.10. The aim is to reduce the volume of work required by Users, Power Park Unit manufacturers and National Grid in assessing the same information at different sites.

In addition, the Manufacturer's Data and Performance Reports can provide a route for detailed data that Power Park Unit manufacturers regard as commercially sensitive to be sent directly to National Grid without publication to the User(s).

Background to Generic Power Park Unit Type Validation

To implement the provision of CP.10 National Grid has developed the generic compliance process which allows manufacturers to work directly with National Grid in order to exchange information and evidence of compliance without data passing through a project chain. Figures D1 to D3 illustrate the differences in the two processes. Figure D1 demonstrates the conventional process where the data flow is always via the power station or power park developer.

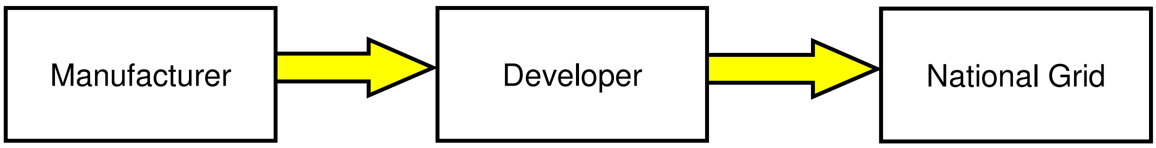


Figure D1 – The conventional compliance process data route.

Figure D2 shows the one time process to fill the generator equipment 'type' register. It may be that information only comes from the manufacturer although a developer may be involved by providing site test opportunities. The data will comprise of a report on one or more of the aspects outlined below.

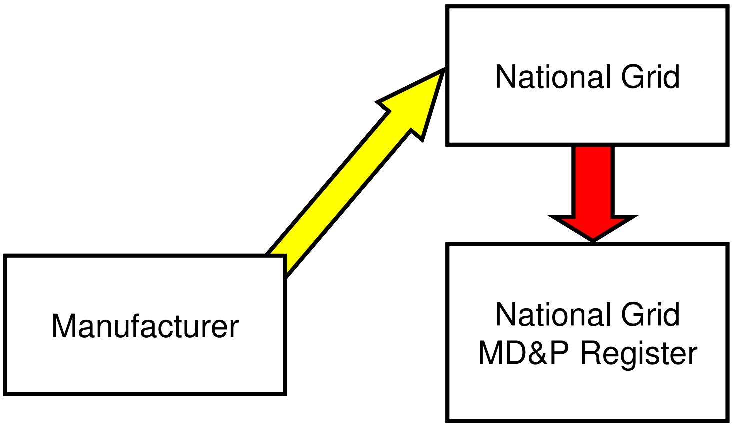


Figure D2 – The Register of Manufacturer's Data & Performance Report
is filled with a selection of generic data.

Figure D3 illustrates the process for referencing and using 'generic' data. Each project can, where appropriate, reference information held in the National Grid generator equipment Register of Manufacturer's Data & Performance Report substituting information that they are required to submit before connecting to the National Electricity Transmission System and in lieu of some aspects of Grid Code testing. Developers will not have access to this information from National Grid and the only requirement is to obtain the correct reference from the manufacturer. If no relevant or insufficient data is held in the Register of Manufacturer's Data & Performance Report then the data must be provided in full by the developer.

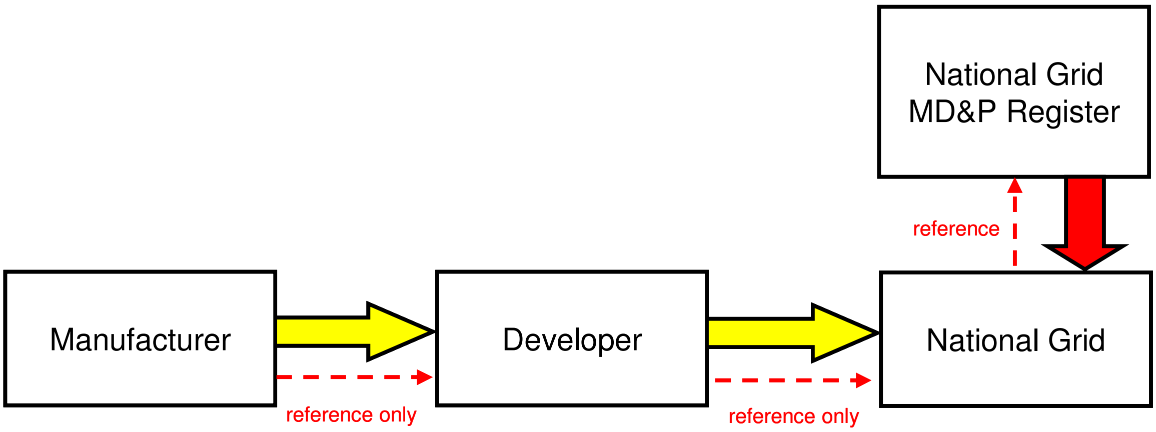


Figure D3 – The generic data (red arrow) is referenced but cannot be seen by the developer.
There will still be some requirement for site specific data (yellow arrow).

Confidentiality Provisions

Data submitted by developers under the Data Registration Code (Grid Code) is protected by the confidentiality agreement contained in the Connection and Use of System Code (CUSC) and System Operator Transmission Owner Code (STC). This does not explicitly cover generic data sent from manufacturers directly to National Grid as it does not necessarily relate to a specific project. It is therefore recommended for manufacturers to sign a confidentiality agreement with National Grid prior to any exchange of information.

Guidance Notes – Power Park Modules

Please note that National Grid cannot sign individual manufacturer's confidentiality agreements as they may not cover the following aspects which are necessary to participate in the generic compliance process.

The following aspects are typical of the provisions of a confidentiality agreement between a manufacturer and National Grid in relation to registering generic Manufacturers Data and Performance Reports information with National Grid.

1) This agreement has been written to reflect the confidentiality provisions in the CUSC which deals with the confidentiality of data as between National Grid and Developers generally. National Grid will NOT however be permitted to release this 'generic' information back to developers (with the exception of the generic information document reference as originally submitted) which is unlike data submissions received through the normal project chain.

2) Some aspects of data must be passed to other Transmission System Operators and Owners in GB for system operation and design reasons as per the System Operator and Transmission Owner Code (STC).

3) The 'Purpose' as defined in the Agreement reflects the purposes for which National Grid do (and are permitted under the CUSC) to use information provided to National Grid by developers through the normal project chain.

4) The agreement is subject to the laws of England & Wales because the entire framework within which this data will be used is structured around English law and if the data was directly provided by a Developer it would be subject to English law.

5) Company Policy requires National Grid business areas to adopt information and records management procedures that comply with all relevant legal requirements and are consistent with best practice as applied to their business needs. The records management procedure for this area provides that this data must be kept for 7 years after the data is last used. This therefore requires that the data should be kept for a period equating to the life of any plant it refers to plus a period of 7 years. This is in line with normal project data submissions direct from developers.

6) National Grid may pass back information (e.g. computer models) to the manufacturer but does not accept any liability in respect of its accuracy.

If this agreement is not signed then the standard Grid Code data requirements apply and all data will need to be provided through the project chain. Failure to supply adequate data by either of these methods will result in non-compliance by the developer with the GB Grid Code and possible disconnection or denial of permission to connect to the GB transmission system.

Areas Suitable for Manufacturer's Data & Performance Report

The Grid Code (CP.10.2) allows the Fault Ride Through capability and the Power Park Module mathematical model to be covered by a Manufacturer's Data & Performance Report. The manufacturer may chose to complete one or both of the above mentioned areas. In each case the manufacturer should submit a detailed report to National Grid for approval and consequent submission into the Manufacturer's Data & Performance Report Register.

To achieve registration for the item Fault Ride Through capability a series of tests and data submissions will be developed to demonstrate the performance characteristics of a single Power Park Unit. Details of these tests and submissions are to be agreed between the Power Park Unit manufacturer and National Grid. National Grid may wish to witness some or all of these tests.

To achieve registration for a Power Park Module mathematical model National Grid and the Power Park Unit manufacturer will need to agree a series of simulations and data submissions in relation to a specific mathematical model of the Power Park Unit and associated control systems in line with the requirements outlined in PC.A.5.4.2. In addition the performance of this model should be validated against test results including faults, voltage steps and frequency changes as is deemed to be appropriate by National Grid.

Submitting Data into the Register of Manufacturer's Data & Performance Report

Manufacturers considering registration should talk to National Grid early in their planning stage.

In order to be considered for registration, the Power Park Unit manufacturer should submit a report to National Grid outlining the details and results as appropriate for its consideration. Each report should have an appropriate reference including manufacturer name, type of report (e.g. Fault Ride Through etc.), Power Park Unit type, date and report version number to permit referencing in future projects or for updates.

National Grid will, following submission of all required reports and data, confirm to the Power Park Unit manufacturer in writing whether the Power Park Unit report has been accepted. Once accepted the Manufacturer's Data & Performance Report Register status will be updated to indicate the acceptance in respect of the relevant Grid Code requirement.

Summary of Grid Code Fault Ride Through Requirements

This section summarises the requirements for all new Power Park Modules contained in CC.6.3.15 of the Grid Code.

The Grid Code 'fault ride through' requirements apply to all faults on the 275kV or 400kV National Electricity Transmission System. The requirements vary depending on the type of fault and the Supergrid voltage profile (duration of fault or voltage dip).

These requirements can be conveniently referred to in the context of two separate fault modes (A & B, which are respectively covered by CC.6.3.15.1(a) and CC.6.3.15.2(b) of the Grid Code).

'Mode A' Requirements - first 140msec of a fault

'Mode A' refers to the first 140msec of three-phase, phase to phase, two-phase to earth or single-phase to earth faults.

Throughout this period the Power Park Module is required to remain transiently stable and connected for all Supergrid phase voltages down to a minimum of 0%. It should also generate the maximum possible reactive current without exceeding the transient rating limit of the Power Park Module or any constituent element.

Within 0.5 seconds, following fault clearance and restoration of the Supergrid voltage to at least 90% of nominal, the Power Park Module must restore the Active Power output to at least 90% of the level available immediately before the fault.

It is anticipated that in achieving this response the control system may be under damped. This will be considered acceptable provided any oscillations decay in a suitably short period and that whilst the oscillations are present the average power delivered corresponds with the levels required were the oscillations not present.

Although the voltage will begin to recover upon fault clearance (within 140msec) it may not necessarily reach 90% voltage within the 140msec period as illustrated in the Appendix of the Connection Conditions (CC.A.4.2). If the Supergrid Voltage has not restored to at least 90% within 140msec then the remaining fault period can be assumed to have a balanced retained voltage and that 'Mode B' requirements will then apply for the remainder of the fault period.

'Mode B' Requirements - fault period beyond the first 140msec

'Mode B' refers to a period of balanced voltage reduction due to power system transients caused by remote faults or the period following clearance of Supergrid faults where the voltage remains reduced for a period.

Throughout this period the Power Park Module is required to remain transiently stable and connected. It must maintain Active Power at least in proportion to the retained balanced Supergrid Voltage and generate the maximum possible reactive current without exceeding the transient rating limit of the Power Park Module or any constituent element.

Within 1 second, following fault clearance and restoration of the Supergrid voltage to at least 90% of nominal, the Power Park Module must restore the Active Power output to at least 90% of the level available immediately before the fault. Once again, appropriately damped active power oscillations shall be acceptable provided the total energy delivered during the period of the oscillation shall be 90% or more.

The worst case duration for which Mode B requirements apply can be calculated by taking the lowest voltage occurring after the first 140msec and finding where it intersects the profile illustrated in CC.A.4.3.

Requirements for Induction Generators

Induction Generators and Doubly Fed Induction Generators typically deliver large amounts of lagging reactive current on application of a fault, which is frequently followed by the delivery of leading current. There after, the current level is dependant upon the technology used and its configuration. For these types of machines, this type of response will be considered on a case by case basis and is likely to be accepted provided:

1. the control system does not introduce extended delays
2. the lagging current contribution is limited to within the equipment capability

Fault Ride Through Testing

The manufacturer may demonstrate fault ride through using tests appropriate to the facilities available. However, a sufficiently large selection of results for balanced and unbalanced faults of varying duration must be provided to replicate the Mode A and B requirements.

National Grid expects the tests to replicate each fault type (3-phase, phase-phase, two-phase to earth and single-phase to earth) with varying magnitudes. The tests should illustrate any changes in characteristics or internal operating modes that depend upon fault severity. For example DFIG wind turbines that utilise crowbar or similar devices should implement tests that illustrate the crowbar inception operating level and any consequential Power Park Unit characteristics, such as active and reactive power fault contribution and power recovery characteristic.

Tests should be repeated at a number of operating points. For example:

- Rated MW
- 70% MEL when MEL is greater than or equal to Rated MW
- SEL when SEL is no greater than DMOL.

Fault Ride Through testing involves applying simulated fault conditions, by applying short circuits, into known impedances to real systems. Compliance with fault ride through may be demonstrated by test conditions which are different to those specified in this sub section and different to the requirements specified in the grid code, provided:

1. The test conditions are more severe.
2. They encompass all of the various fault scenarios covered by the grid code.
3. They can be used in conjunction with the studies to demonstrate compliance.

Guidance Notes – Power Park Modules

The set of tests shown in the table below is recommended.

% Retained Supergrid Voltage	3 phase	Phase to phase	2 phase to Earth	1 phase to Earth	Grid Code Ref
0	0.14s	0.14s	0.14s	0.14s	CC6.3.15a
30	0.384				CC6.3.15b Including Figure 5
50*	0.71s				
80	2.5s				
85	180s				

Figure D4 – Fault Ride Through – Type Tests

The purpose of the tests is to characterise the Power Park Unit such that its limit of operation for retained voltage (at the terminals of the Power Park Unit) is known. At the end of the test the results should indicate the level of voltage depression the unit can with stand for the times specified. Whilst the volts are depressed the Power Park Unit should deliver power in the same proportion as the volts and then recover once volts are restored.

Ideally Power Park Units will achieve the voltage levels and durations listed in the table above as this would indicate that the unit is fully compliant without the need for the study evidence. However these levels are unlikely to occur at the Power Park Unit terminals in practice because of the impedance between the fault location and the Power Park Unit. Consequently, increased test voltage levels above those specified are typically acceptable for most circumstances but require further study evidence (on a case by case basis) to demonstrate that the levels which occur at the a particular Power Park are greater than those which the Power Park Units are capable of riding through.

The results should demonstrate the Power Park Unit can survive at 0% retained volts for 140ms or if the unit can not operate down to zero, minimum retained volts the unit can operate at for 140ms. The unit must be capable of recovering once the fault is removed. This should be determined for all fault modes: 3 phase, phase to phase and single and two phases to earth faults.

In addition the results should characterise, at appropriate points, the fault contribution for Mode B voltage depression after a three phase fault. To do this the voltage at the Power Park Unit terminals should be reduced to the voltages specified below (in separate tests):

1. 30% volts for a period of 384ms
2. 50% volts for a period of 710ms
3. 80% volts for a period of 2.5 secs
4. 85% volts for a period of 180 secs

At the end of each of these tests the voltage should be returned to 90% until conditions have stabilised or for a minimum period of 180 seconds.

Power Park Unit designs which incorporate features such as crowbar thyristor protection to enable them to meet the fault ride through requirements, should additionally indicate for each test whether the crowbar or other protection modes were active.

Guidance Notes – Power Park Modules

The tests should be performed on a single Power Park Unit using the test circuit shown below.

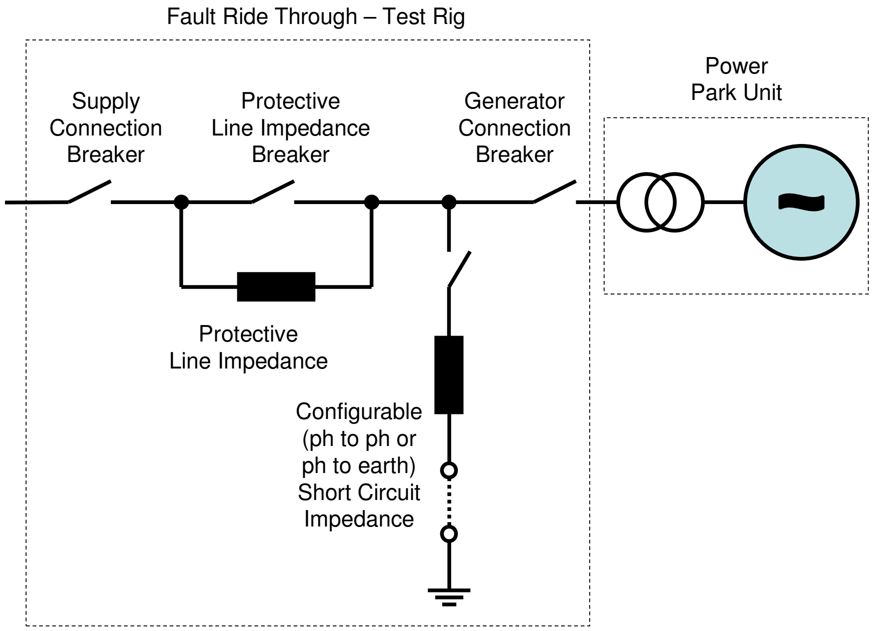


Figure D5

Test No	Step	Description	Notes
1		• Operate the Power Park Unit (PPU) at nominal volts and appropriate output • Apply a 3ph short reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 3 otherwise proceed to test 2	Mode A
2		• Repeat test 1 to determine the minimum retained volts until the unit can operate at for a period of 140ms	Mode A
3	.	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a 1ph to earth short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 5 otherwise proceed to test 4	Mode A
4	.	• Repeat test 3 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A

5	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a 2ph to earth short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 7 otherwise proceed to test 6	Mode A
6	.	• Repeat test 5 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A
7	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a phase to phase short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 9 otherwise proceed to test 8	Mode A
8	.	• Repeat test 7 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A
11	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a reduction in 3ph voltage to 30% • Hold the voltage at 30% for 384ms • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
12	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a reduction in 3ph voltage to 50% • Hold the voltage at 50% for 710ms • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
13	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a reduction in 3ph voltage to 80% • Hold the voltage at 80% for 2.5 seconds • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
14	. . . . .	• Operate the Power Park Unit (PPU) at nominal volts and appropriate output. • Apply a reduction in 3ph voltage to 85% • Hold the voltage at 85% for 180 seconds • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B

Appendix E - Response to Frequency Changes and Intermittent Power Source Variation

Scope

This Appendix is intended to provide guidance for manufacturers on the how control systems should react to changes in system frequency with fluctuations in the intermittent power source. This includes operation in both Frequency Sensitive and Limited Frequency Sensitive Modes.

Several scenarios (high and low system frequency and various wind variations) are covered for each of four different operating points, to help explain how the response should be provided.

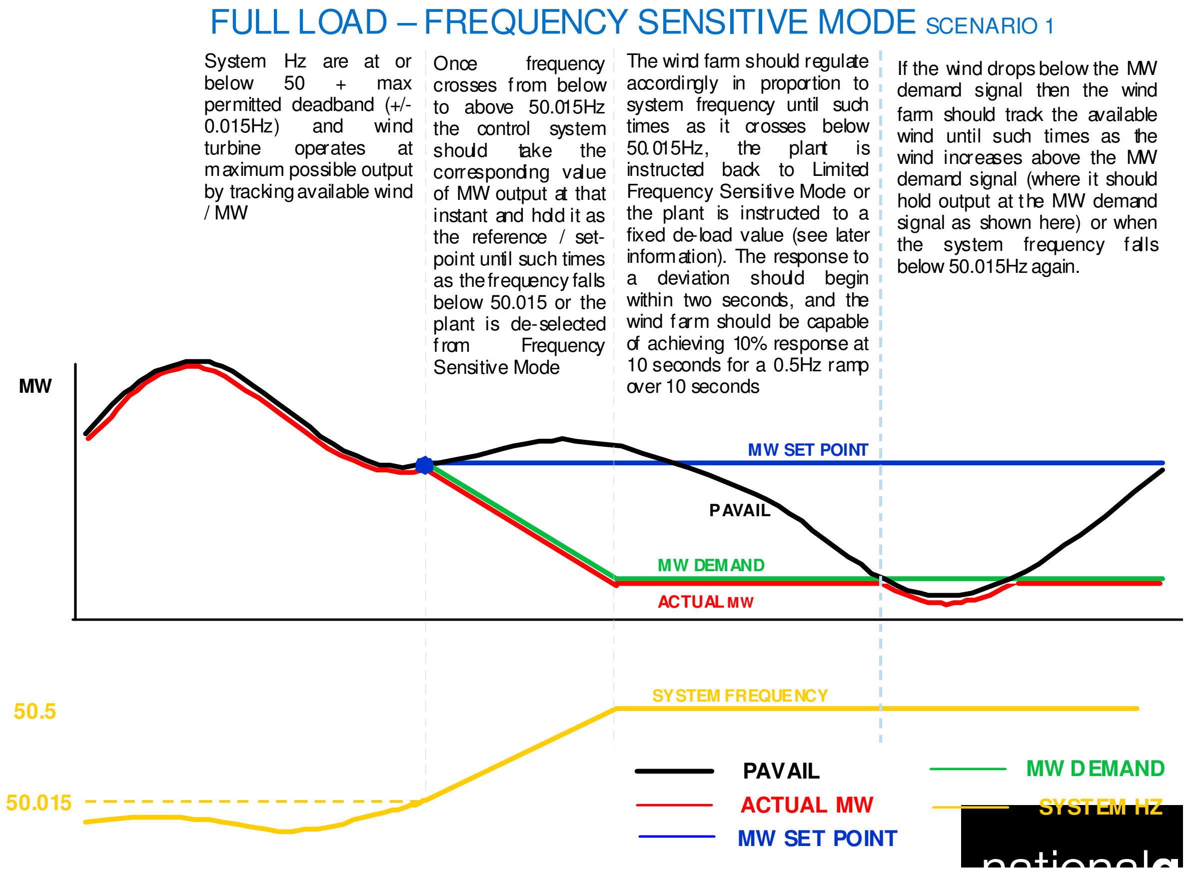
The four different operating points considered are

1) Frequency Sensitive Mode at full available MW / wind (high frequency response only)
2) Frequency Sensitive Mode at a de-load value below maximum available MW / wind

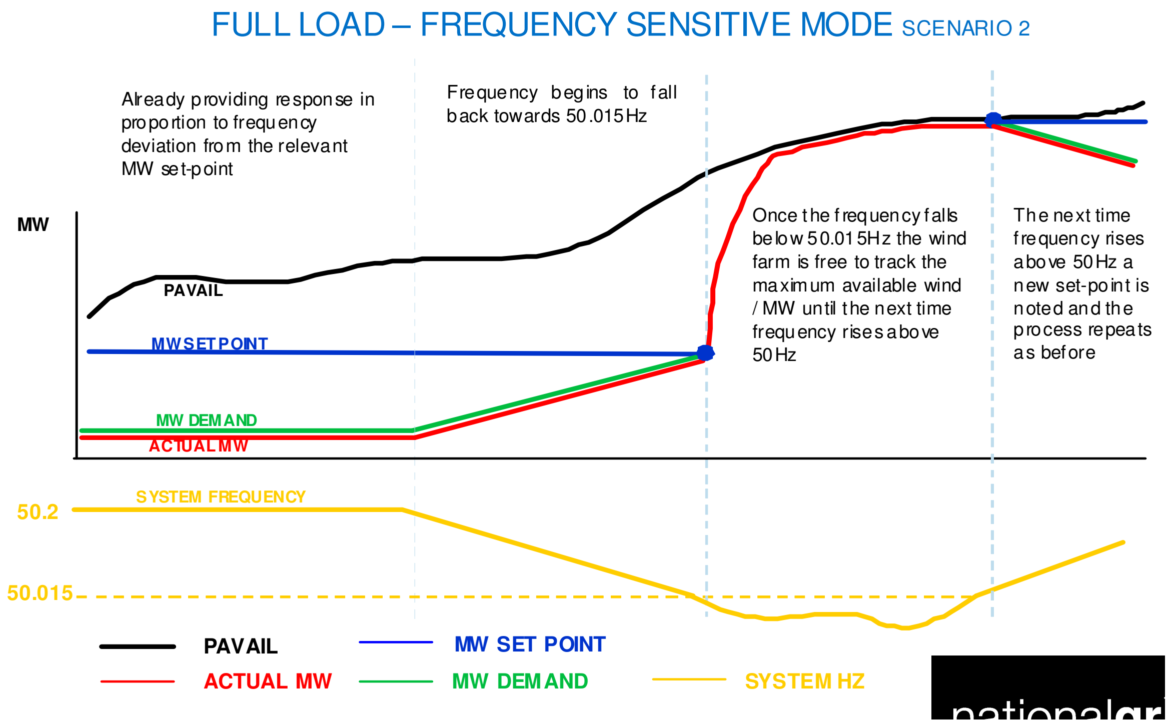
3) Limited Frequency Sensitive Mode at full available MW / wind
4) Limited Frequency Sensitive Mode at a de-load value below maximum available MW / wind

Frequency Sensitive Mode at Full Load

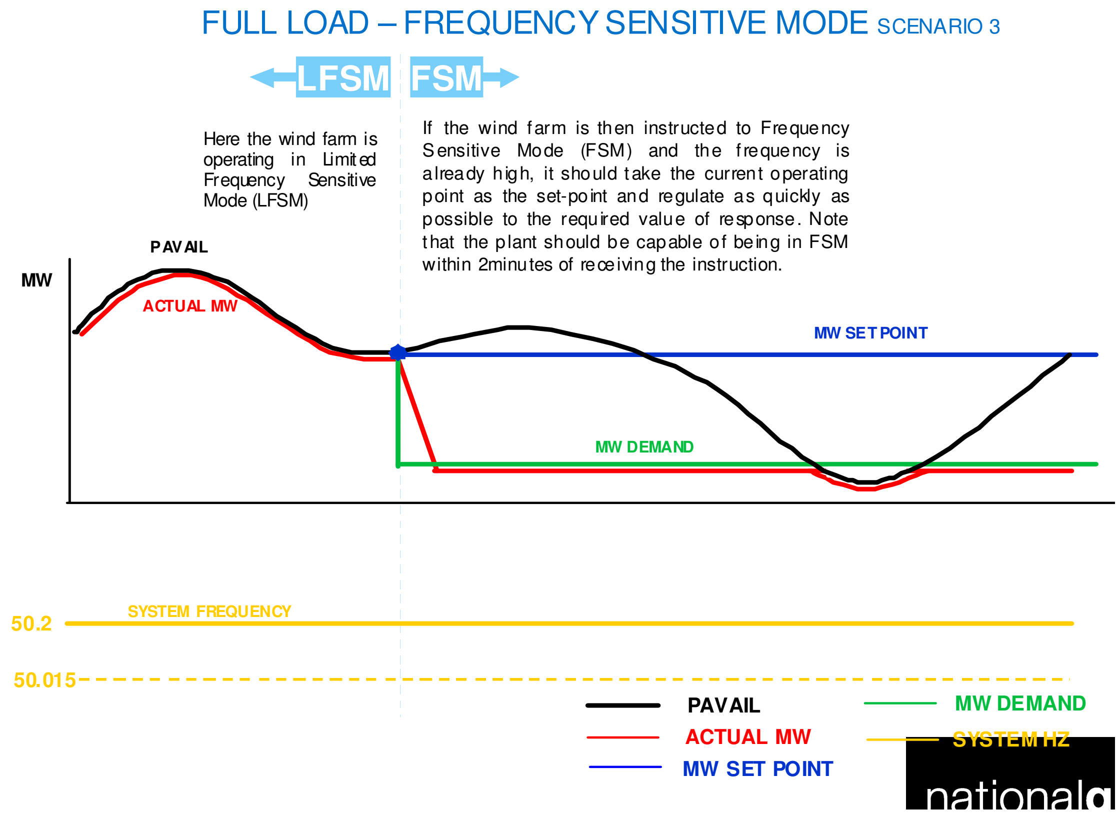
Scenario 1 – Start of a high frequency event followed by a drop in wind speed / available power.



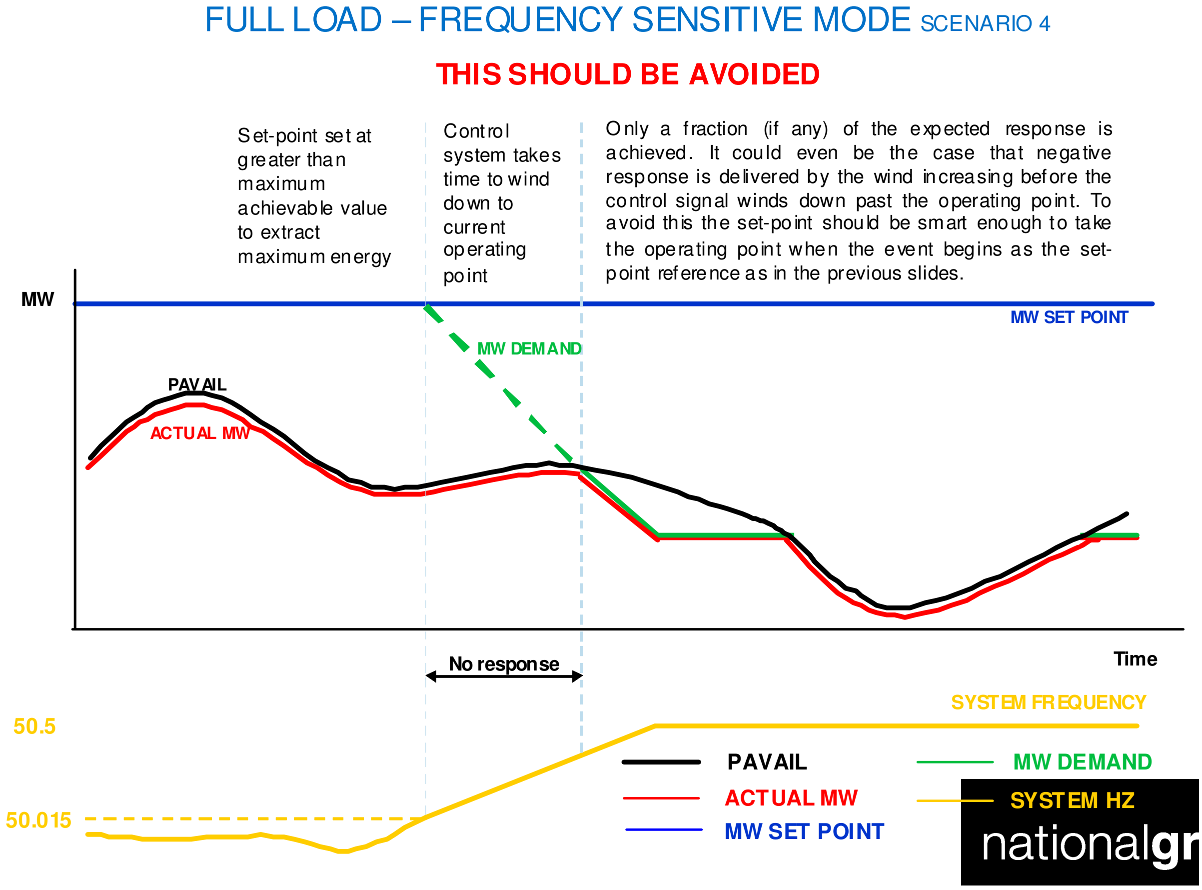
Scenario 2 – End of a high frequency event followed by another high frequency event.



Scenario 3 – Instructed to Frequency Sensitive Mode (from Limited Frequency Sensitive Mode) while system frequency is already high.



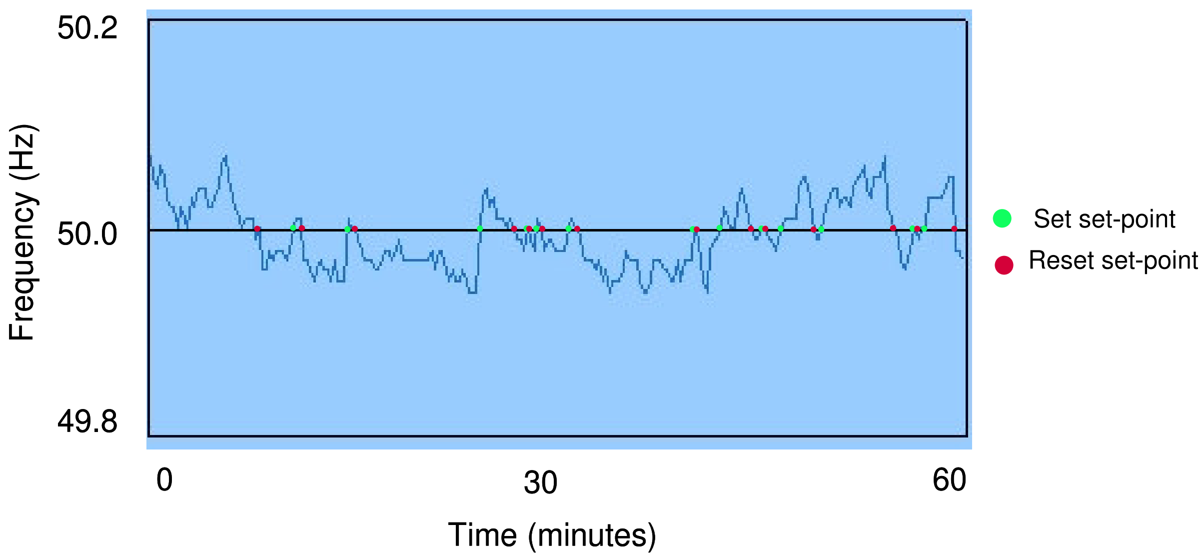
Scenario 4 – The case to avoid



Set and Re-set Set-point

In order to provide consistent and sustainable response to high frequency the control system has to select the power park module output as a reference when the system frequency goes above 50Hz and release the reference when system frequency goes below 50Hz. The example below illustrates when to set and re-set the set-point using a real system frequency trace.

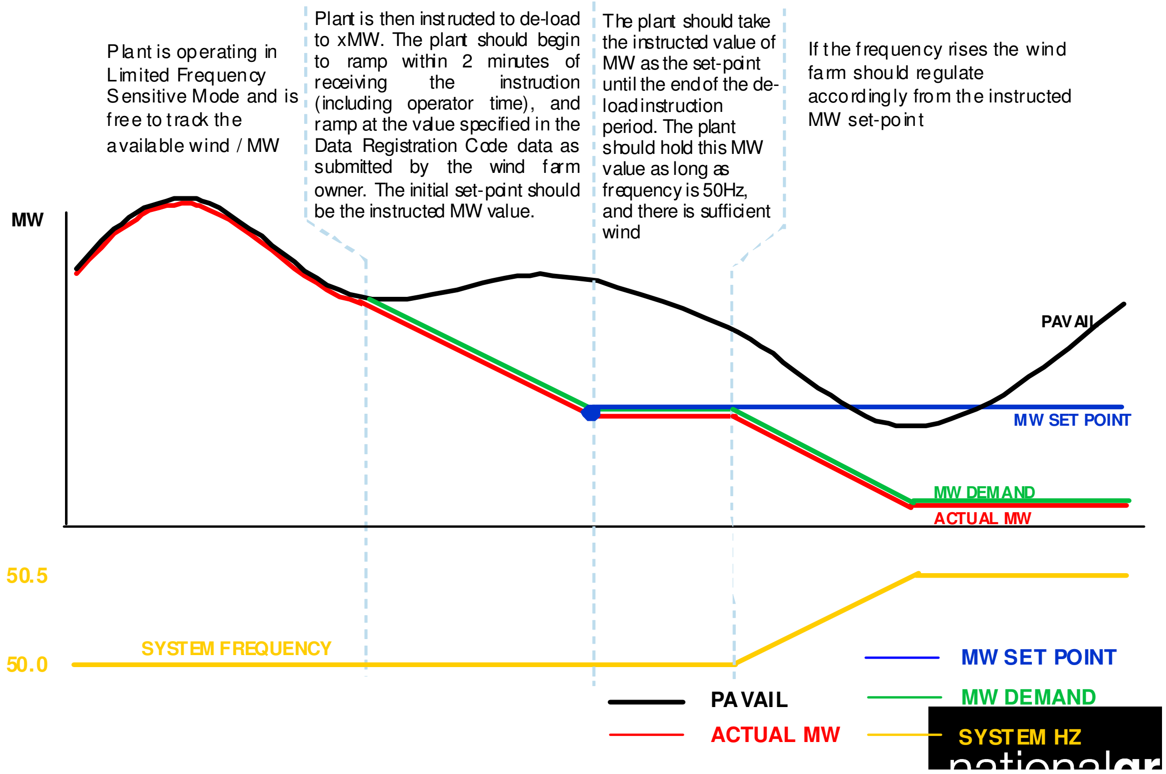
The green dots indicate where the system frequency passes from below 50Hz to above 50Hz. At this point the wind farm control system should take and hold the corresponding MW output value at that instant as the wind farm set-point. The wind farm should then regulate in relation (wind conditions permitting) to that set-point until such times as the frequency falls below 50Hz (red dots), the unit is instructed back into Limited Frequency Sensitive Mode or the unit is instructed to a new de-loaded level



Frequency Sensitive Mode At De-Load

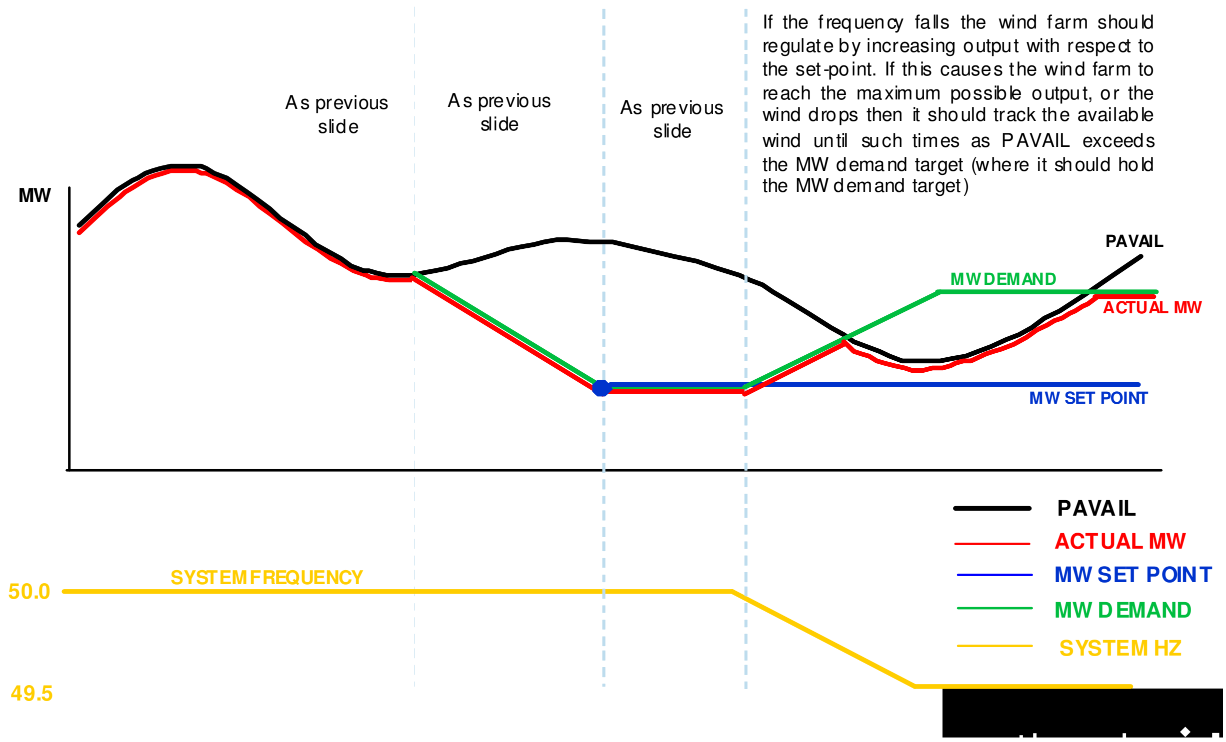
Scenario 1 – Increase in system frequency after instructed to de-load

DE-LOAD – FREQUENCY SENSITIVE MODE SCENARIO 1



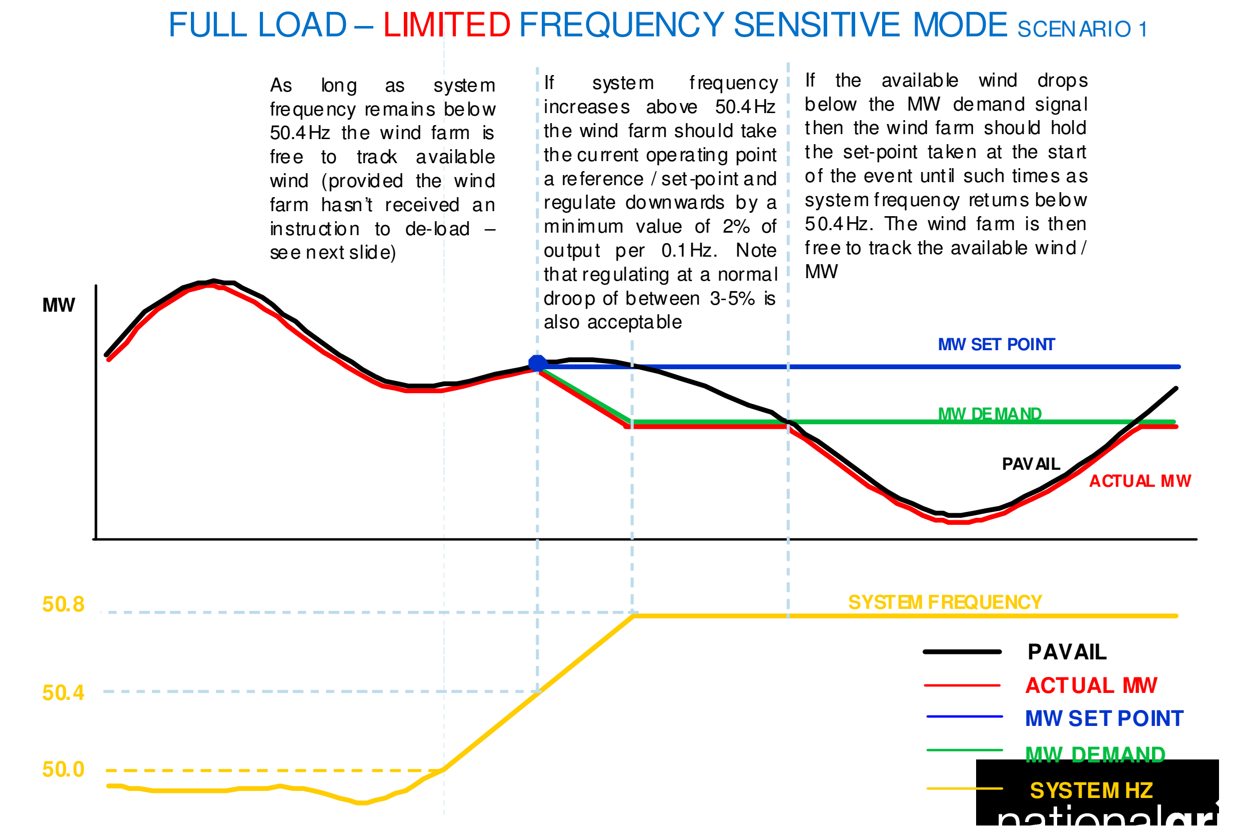
Scenario 2 – Decrease in system frequency after instructed to de-load

DE-LOAD – FREQUENCY SENSITIVE MODE SCENARIO 2

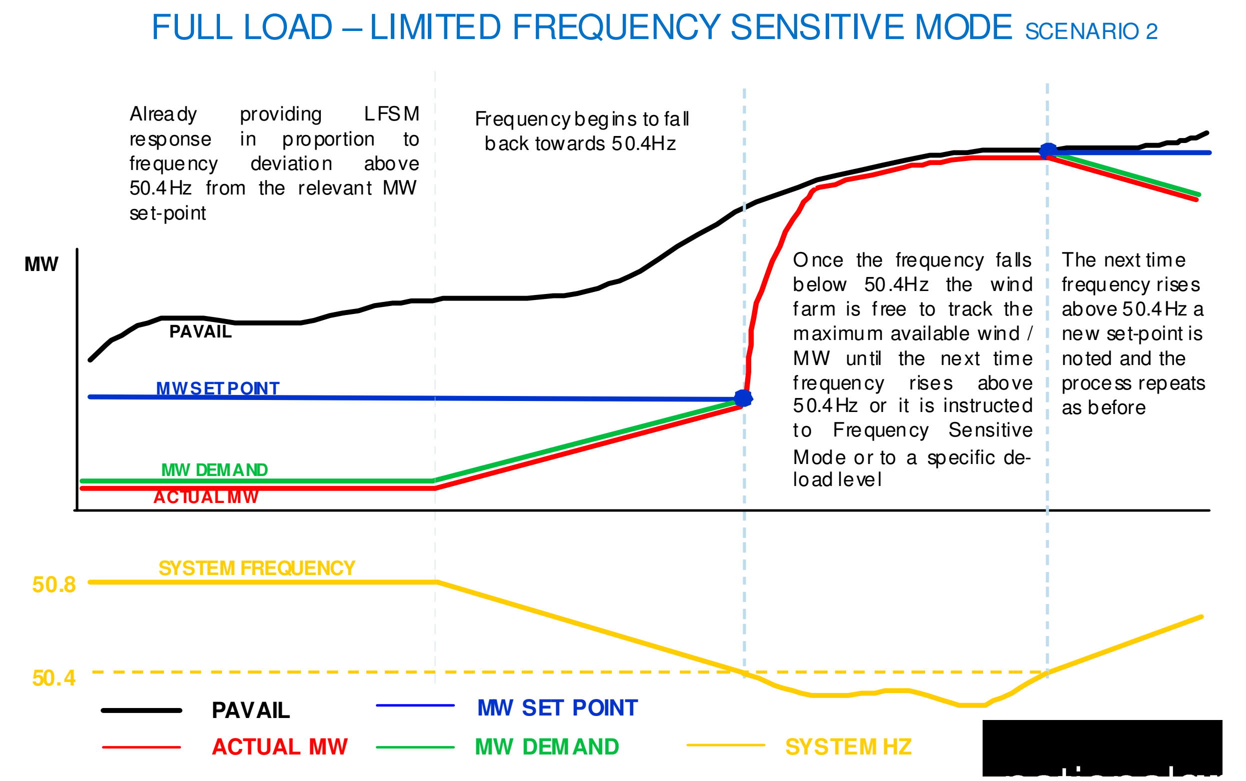


Limited Frequency Sensitive Mode

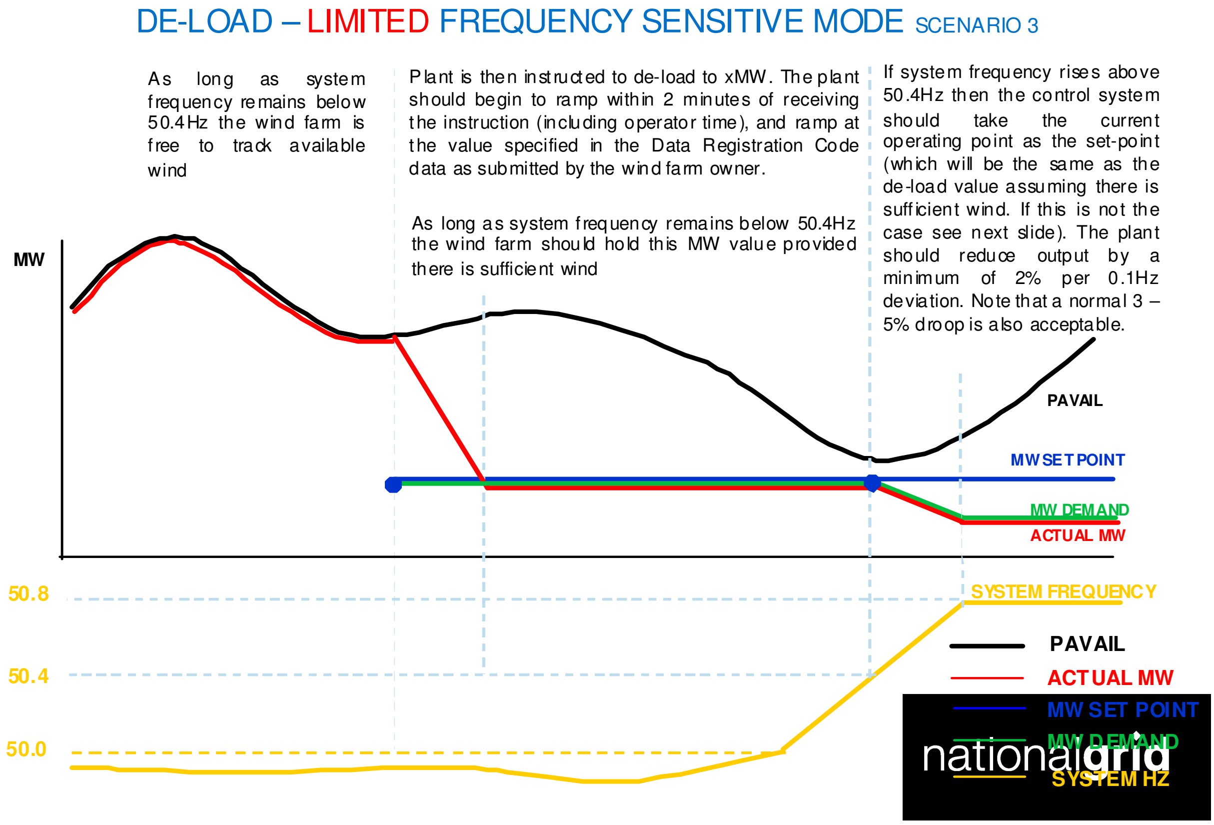
Scenario 1 – Limited Frequency Sensitive Mode from full load (frequency rising above 50.4Hz)



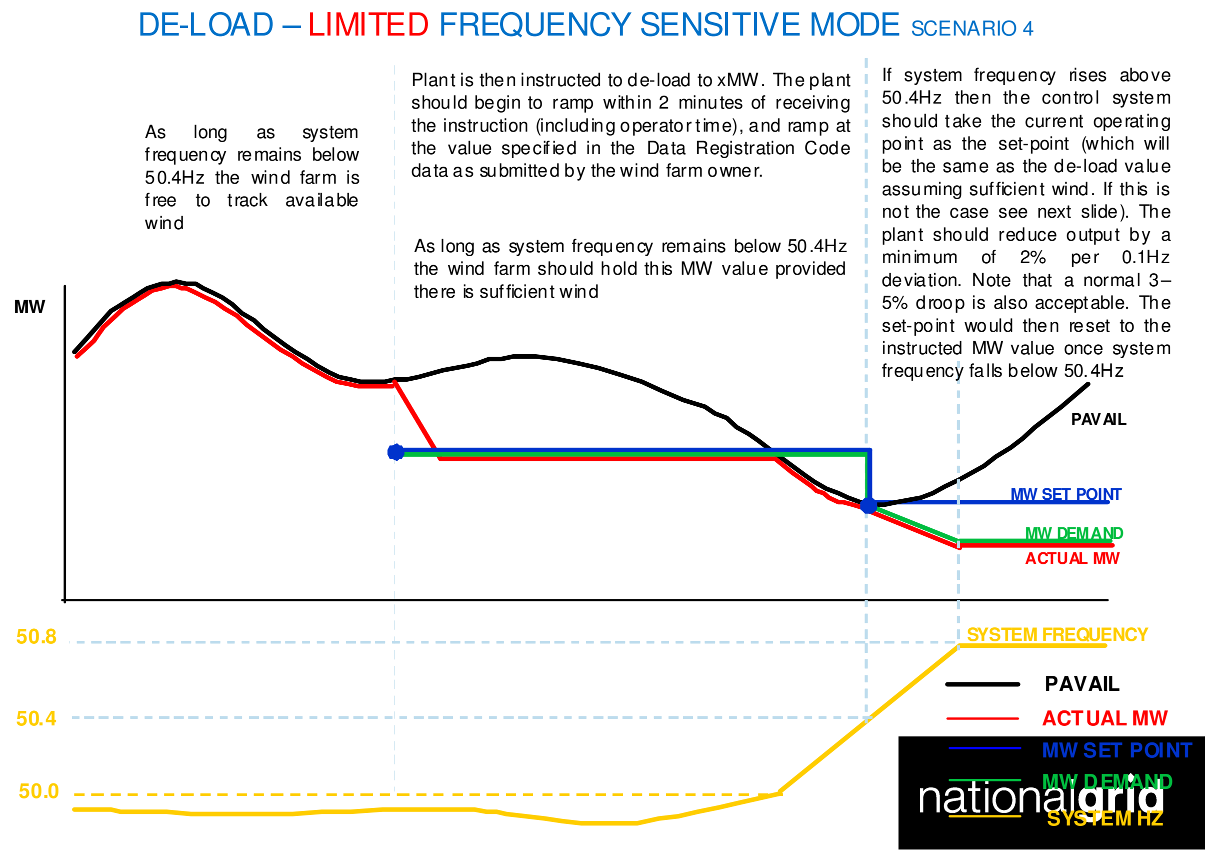
Scenario 2 – Limited Frequency Sensitive Mode from full load (frequency falling below 50.4Hz)



Scenario 3 – Limited Frequency Sensitive Mode from de-load position



Scenario 4 – Limited Frequency Sensitive Mode from de-load position with a drop in available wind / MW



Summary

When de-loaded in GB the wind farm is instructed to a set MW value rather than a delta MW value from available MW (PAVAIL). While this may cause variability in the headroom for frequency response it allows the system to be balanced in an effective manner when large amounts of wind generation are connected (known as system balancing rather than frequency response).

For Frequency Sensitive Mode at full load the wind farm should take and hold the operating point (MW value) at the instance the system frequency crosses from below 50.015 to above 50.015Hz as the set-point.

Limited Frequency Sensitive Mode at all times the wind farm should take and hold the operating point (MW value) at the instance the system frequency crosses from below 50.4 to above 50.4Hz as the set-point.

For Frequency Sensitive Mode at a de-loaded value the wind farm should take the instructed MW value as the set-point.

The guidance here applies to the behaviour of the complete wind farm. If frequency controllers are implemented on individual turbines then variations to the suggestions here may have to be made to achieve the desired aims at the point of connection.

The wind farm operator is still required to submit Final Physical Notification (FPN) and Maximum Export Limit (MEL) data as normal. The MEL figure submitted to National Grid should be updated each time it differs from the available power by the greater of 5MW or 5% to ensure that the volume of available response can be correctly calculated.

Not providing the expected response to a frequency deviation may cause premature limits on the amount of wind turbine plant that the system can cope with without detrimental effects on frequency stability. It is therefore essential that the response provided should be repeatable (wind conditions permitting).

Appendix F - Other Technical Information

Calculating Equivalent Impedance for Fault Ride Through Studies

The next two subsections, describe a simplified method of determining the fault ride through capability where the Point of Connection is not the Supergrid. This method relies on substituting the network between the Supergrid and Point of Connection with an equivalent impedance. A reasonable value for the equivalent impedance needs to be determined. The worst case scenario will be the minimum impedance. This minimum impedance can be derived from the maximum fault level at the connection point.

In some cases however, the maximum fault level may include contributions from other generation embedded between the Point of Connection and the Supergrid. Consequently the apparent impedance derived by the maximum fault level may be lower than the actual impedance. This will provide a worst case scenario. The maximum fault level data at the point of connection is readily available and is therefore a reasonable place to start. If this conservative impedance estimate is too arduous more detailed work will be needed to obtain a better impedance estimate.

For Power Parks with a point of connection to the Supergrid, the technique described below is still appropriate however the equivalent impedance (described above) is removed.

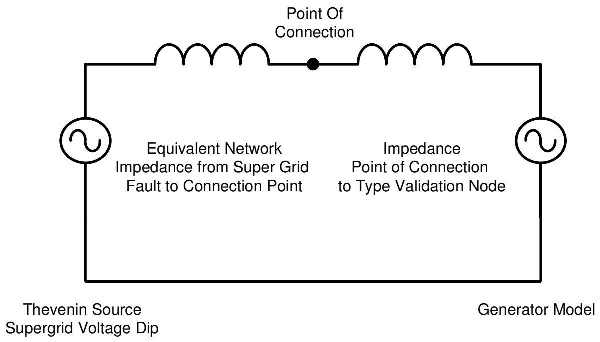
Positive Sequence Studies

The simplified positive sequence network below will generally be accepted as satisfying the 'pps' aspect of studies in Grid Code CP.A.3.5.

In this conservative and simplified case, the network beyond the point of connection is represented by, a controlled Thevenin source and equivalent impedance. The equivalent impedance is derived from the maximum fault level at the point of connection.

The type validation tests were based on benchmarking the Power Park Unit at a node selected by the manufacturer. The impedance between the point of connection and the 'type validation node' must reflect the equivalent aggregated impedance of the Power Park between the point of connection and the same node.

The remaining impedance is the impedance between the 'type validation node' and the point at which the model representation begins (model interface node). In some cases the type validation node and the model interface node will be the same point and this impedance will not be included.

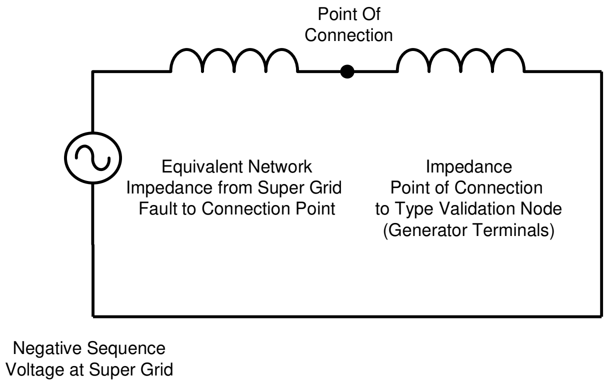


This simplified network can be implemented in a power system analysis package of the Developers choice using the voltage dips specified in Studies 3.1 & 3.2. The results at node 'A' are then compared to the type validation results to confirm ride through capability. The validity of the generator model's contribution to the retained voltage also needs to be confirmed by ensuring that the contribution at 'B' is comparable with the results obtained during the type validation tests for the equivalent profile at 'A'.

Negative Sequence Studies

Similarly the simplified negative sequence network below will generally be accepted as satisfying the 'nps' aspect of Grid Code CP.A.3.5.

The negative sequence network is identical to the positive sequence network except that the generator model and the impedance between the 'type validation node' and the model interface node are replaced with an equivalent negative sequence estimate obtained during the type validation tests.



Solving the load flow for the above network using a voltage source corresponding to the negative sequence magnitude at the Supergrid results in a negative sequence voltage estimate at the type validation node ('A'). The results at node 'A' are then compared to the type validation results to confirm ride through capability.

In the event that the type validation tests show that there is no single equivalent negative sequence impedance then the type validation will record a family of impedances equating to retained negative sequence voltages at the type validation node. The negative sequence studies will then be run iteratively and the impedance value updated until reasonable convergence is obtained.

Technical Information on the Connection Bus Bar

This section illustrates the technical information relating to the connection bus bar that is provided by National Grid

Busbar on National Electricity Transmission System operating at Supergrid Voltage:	**Example 1 (Scottish Power Area 275 kV)**	**275kV**

Item	Max	Min	Unit
Symmetrical Three-phase short circuit level at instant of fault from GB Transmission System (based on transient impedance)	19000	1300	MVA
Equivalent system reactance between the Supergrid Busbar and Power Park Module Point of Connection.	3.9	3.6	% on 100 MVA
Total clearance time for fault on National Electricity Transmission System operating at Supergrid Voltage, cleared by System Back-up Protection (C.C.6.3.15.1 (c))	800		msec

Equivalent Circuit between Supergrid Busbar and Power Park Module Point of Connection

(showing transformer vector groups):

[For CC6.3.15.1 (c) assume system 'nps' impedance pre-and post-fault such that CC6.1.6 limits met]

Equivalent Sequence Impedances for Calculating Unbalanced Short-Circuit Current Contribution

The generator is required to provide the fault infeed from the Power Park Module into the public transmission/distribution network. The data should be submitted in Grid Code DRC Schedule 14. The following transmission/distribution system equivalent sequence impedances may be used by the Generator in calculating unbalanced short-circuit current contribution from the Power Park Module at the entry point unless site specific values have been given. The Generator should confirm the system equivalent sequence impedances that have been used in the submission.

33kV: Z1 = Z2 = 14.580∠88.091º % on a 100 MVA base
Z0 = 159.1∠26.565º % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS and NPS X/R ratio of the 33kV system is equal to 30
- The ZPS X/R ratio of the 33kV system is equal to 0.5
- The short-circuit current contribution from the 33kV distribution system for a 3-phase fault at the entry point is approximately 12kA
- The short-circuit current contribution from the 33kV distribution system for a 1-phase fault at the entry point is approximately 3kA

132kV: Z1 = Z2 = 3.650∠84.289º % on a 100 MVA base
Z0 = 1.460∠84.289º % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the transmission/distribution system is 10.
- The short-circuit current contribution from the transmission/distribution system for a 3-phase fault at the entry point is approximately 12kA
- The short-circuit current contribution from the transmission/distribution system for a 1-phase fault at the entry point is approximately 15kA

275kV: Z1 = Z2 = 0.700∠85.236º % on a 100 MVA base
Z0 = 1.120∠85.236º % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the 275kV system is equal to 12
- The short-circuit current contribution from the 275kV transmission system for a 3-phase fault at the entry point is approximately 30kA
- The short-circuit current contribution from the 275kV transmission system for a 1-phase fault at the entry point is approximately 25kA

400kV: Z1 = Z2 = 0.361∠85.914º % on a 100 MVA base
Z0 = 0.516∠85.914º % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the 400kV system is equal to 14
- The short-circuit current contribution from the 400kV transmission system for a 3-phase fault at the entry point is approximately 40kA
- The short-circuit current contribution from the 400kV transmission system for a 1-phase fault at the entry point is approximately 35kA

Appendix G - Contacting National Grid

There are a number of different departments in National Grid, each with key areas of expertise and responsibilities relevant to connection of a Generator. The complete process is controlled by a Commercial Contact who 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 can be found on the National Grid website.

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 National Electricity System Operator and owns and develops the high-voltage electricity transmission network in England & Wales.