Frequency Response Obligations

Statutory, Code and Operational Standards

This document provides an overview of the statutory, code obligations for frequency response to which NGET must adhere. It also provides a description of NGET's internal standards for frequency response to which NGET's operates the GB Transmission System.

1. Statutory Obligations

Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002 (Amended 2006)[1]

The ESQCR's are decreed under the Electricity Act (section 29). The ESQCR specifies that

- the declared frequency for the system is 50 hertz
- a variation not exceeding 1 percent above or below the declared frequency is permitted

NGET Licence Conditions

Standard licence condition 17 specifies that NGET shall at all times:

a. plan, develop and operate the licensee's transmission system; and

b. coordinate and direct the flow of electricity onto and over the GB Transmission System

in accordance with the GB SQSS together with the STC and Grid Code.

2. GB Security and Quality of Supply Standards (GB SQSS) Obligations[2]

Planning Criteria

- The standard specifies the planning criteria for the direct connection of one or more power stations to the GB Transmission System – Chapter 2 (Design of Generation Connections) as describes below (extract):
  - ⇨ 2.5 For the purpose of applying the criteria of paragraph 2.6, the *loss of power infeed* resulting from a *secured event* shall be calculated as follows:

    2.5.1 the sum of the *registered capacities* of the *generating units* disconnected from the system by a *secured event*, plus

    2.5.2 the planned import from any *external systems* disconnected from the system by the same event, less

    2.5.3 the *forecast minimum demand disconnected* from the system by the same event but excluding (from the deduction) any demand forming part of the *forecast minimum demand* which may be automatically tripped for system frequency control purposes and excluding (from the deduction) the demand of the largest single end customer.
  - ⇨ 2.6 Generation connections shall be planned such that, starting with an *intact system*, the consequences of *secured events* shall be as follows:-

    2.6.1 following a *fault outage* of any single *transmission circuit*, no *loss of power* shall occur;

    2.6.2 following the *planning outage* of any single section of *busbar* or mesh corner, no *loss of power infeed* shall occur;

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1 The Electricity Safety, Quality and Continuity Regulations 2002 http://www.opsi.gov.uk/si/si2002/20022665.htm

2 GB SQSS is available on National Grid's website – https://www.nationalgrid.com/NR/rdonlyres/FBB211AF-D4AA-45D0-9224-7BB87DE366C1/15460/GB_SQSS_V1.pdf

2.6.3 following a *fault outage* of any single *generation circuit* or single section of *busbar* or mesh corner; the *loss of power infeed* shall not exceed the *normal infeed loss risk*;

2.6.4 following the concurrent *fault outage* of any two *transmission circuits* or any two *generation circuits* on the same *double circuit overhead line,* or the *fault outage* of any single *busbar* coupler circuit breaker, or *busbar* section circuit breaker, or mesh circuit breaker, the *loss of power infeed* shall not exceed the *infrequent infeed loss risk*;

2.6.5 following the *fault outage* of any single *transmission circuit*, single section of *busbar* or mesh corner, during the *planned outage* of any other single *transmission circuit* or single section of *busbar* or mesh corner, the *loss of power infeed* shall not exceed the *infrequent infeed loss risk*;

2.6.6 following the *fault outage* of any single *busbar* coupler circuit breaker or *busbar* section circuit breaker or mesh circuit breaker, during the *planned outage* of any single section of *busbar* or mesh corner, the *loss of power infeed* shall not exceed the *infrequent infeed loss risk*.

Operational Criteria

- The standard specifies the normal operational criteria of the GB Transmission System – Chapter 5 (Operation of the GB transmission system) as described below (extract):
  - ⇨ 5.1 The *GB transmission system* shall be operated under *prevailing system conditions* so that for the *secured event* of a *fault outage* of any of the following:

    5.1.1 a single *transmission circuit*, reactive compensator or other reactive power provider; or

    5.1.2 the most onerous *loss of power infeed*; or

    5.1.3 where the system is designed to be secure against a fault outage of a section of busbar or mesh corner under planned outages conditions, a section of busbar or mesh corner,

    there shall not be any of the following:

    5.1.4 a *loss of supply capacity* except as specified in Table 5.1;

    5.1.5 *unacceptable frequency conditions*;

    5.1.6 *unacceptable overloading* of any *primary transmission equipment*;

    5.1.7 *unacceptable voltage conditions*; or

    5.1.8 *system instability*.

  - ⇨ 5.3 The *GB transmission system* shall be operated under *prevailing system conditions* so that for the *secured event* of a *fault outage* of:

    5.3.1 a *double circuit overhead line*; or

    5.3.2 a section of *busbar* or mesh corner

    there shall not be any of the following:

    5.3.3 a *loss of supply capacity* greater than 1500 MW;

    5.3.4 *unacceptable frequency conditions*; or

    5.3.5 *unacceptable voltage conditions* affecting one or more *Grid Supply Points* for which the total *group demand* is greater then 1500 MW; or

    5.3.6 *system instability* of one or more generating units connected to the *supergrid*.

GB SQSS Definitions

- *Loss of Power Infeed*

  The output of a *generating unit* or a group of *generating units* or the import from *external systems* disconnected from the system by a *secured event*, less the demand disconnected from the system by the same *secured event*.
  - Operational criteria include the output of a single generating unit, CCGT Module, boiler, nuclear reactor or DC Link bi-pole loss as a result of an event.

- *Infrequent Infeed Loss Risk*
  - That levels of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5Hz to 50.5Hz for more than 60 seconds. Until reviewed this is 1320MW

- *Normal Infeed Loss Risk*
  - That levels of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5Hz. Until reviewed this is 1000MW

- *Unacceptable Frequency Conditions*
  - These are conditions where:
    i. the *steady state* frequency falls outside that statutory limits of 49.5Hz to 50.5Hz; or
    ii. a transient frequency deviation on the *MITS* persists outside the above statutory limits and does not recover to within 49.5Hz to 50.5Hz within 60 seconds.

  Transient frequency deviations outside the limits of 49.5Hz and 50.5Hz shall only occur at **intervals which ought reasonably be considered as infrequent**. It is not possible to be prescriptive with regard to the type of *secured event* which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which NGET shall adjust from time to time to meet the security and quality requirements of this Standard.

3. Code Obligations

Frequency response requirements are specified in the Grid Code[3] – Connection Conditions (CC.6.1.2, CC.6.1.3, CC.6.3.6 and CC.6.3.7) and are specified as follows.

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

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

Frequency Range	Requirement
47.5Hz – 52Hz	Continuous operation is required
47Hz – 47.5Hz	Operation for a period of at least 20 seconds is required each time the **Frequency** is below 47.5Hz

The Low Frequency Relay settings (CC.A.5.4) are aligned with the above requirements.

[3] Grid Code is available on National Grid's website – https://www.nationalgrid.com/uk/Electricity/Codes/gridcode/gridcodedocs/

▪ CC.6.3.6 (a) Each:

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

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

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

(iv) **Power Park Module** in operation in Scotland on or after 1 January 2006 (with a **Completion Date** after 1 July 2004 and in a **Power Station** with a **Registered Capacity** of 50MW or more),

must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **GB Transmission System** or the **User System** in which it is **Embedded**.

▪ CC.6.3.7 (a) Each **Generating Unit, DC Converter** or **Power Park Module** (excluding **Power Park Modules** in Scotland with a **Completion Date** before 1 July 2004 or **Power Park Modules** in a **Power Station** in Scotland with a **Registered Capacity** less than 50MW) must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (**BC3**). In the case of a **Power Park Module** the frequency or speed control device(s) may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both. The Frequency control device(s) (or speed governor(s)) must be designed and operated to the appropriate:

(i) **European Specification**; or

(ii) in the absence of a relevant **European Specification**, such other standard which is in common use within the European Community (which may include a manufacturer specification);

as at the time when the installation of which it forms part was designed or (in the case of modification or alteration to the **Frequency** control device (or turbine speed governor)) when the modification or alteration was designed.

The **European Specification** or other standard utilised in accordance with sub-paragraph CC.6.3.7 (a) (ii) will be notified to **NGET** by the **Generator** or **DC Converter Station** owner or, in the case of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded DC Converter Station** not subject to a **Bilateral Agreement**, the relevant **Network Operator**:

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

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

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

(iv) as soon as possible prior to any modification or alteration to the **Frequency** control device (or governor); and

(b) The **Frequency** control device (or speed governor) in co-ordination with other control devices must control the **Generating Unit, DC Converter** or **Power Park Module Active Power Output** with stability over the entire operating range of the **Generating Unit, DC Converter** or **Power Park Module**; and

(c) The **Frequency** control device (or speed governor) must meet the following minimum requirements:

(i) Where a **Generating Unit, DC Converter** or **Power Park Module** becomes isolated from the rest of the **Total System** but is still supplying **Customers**, the **Frequency** control device (or speed governor) must also be able to control **System Frequency** below 52Hz unless this causes the **Generating Unit, DC Converter** or **Power Park Module** to operate below its **Designed Minimum Operating Level** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt the **Generating Unit, DC Converter** or **Power Park Module** is only required to operate within the **System Frequency** range 47 - 52 Hz as defined in CC.6.1.3.;

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

(iii) in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the **Frequency** control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the speed governor deadband should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**;

For the avoidance of doubt, the minimum requirements in (ii) and (iii) for the provision of **System Ancillary Services** do not restrict the negotiation of **Commercial Ancillary Services** between **NGET** and the **User** using other parameters; and

(d) A facility to modify, so as to fulfil the requirements of the **Balancing Codes**, the **Target Frequency** setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 ±0.1 Hz should be provided in the unit load controller or equivalent device.

(e) (i) Each **Generating Unit** and/or **CCGT Module** which has a **Completion Date** after 1 January 2001 in England and Wales, and after 1 April 2005 in Scotland, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

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

(iii) Each **Power Park Module** in operation in England and Wales with a **Completion Date** on or after 1 January 2006 must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(iv) Each **Power Park Module** in operation on or after 1 January 2006 in Scotland (with a **Completion Date** on or after 1 April 2005 and a **Registered Capacity** of 50MW or more) must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(f) For the avoidance of doubt, the requirements of Appendix 3 do not apply to:

(i) **Generating Units** and/or **CCGT Modules** which have a **Completion Date** before 1 January 2001 in England and Wales, and before 1 April 2005 in Scotland, for whom the remaining requirements of this clause CC.6.3.7 shall continue to apply unchanged: or

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

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

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

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

- CC.8 specifies the Ancillary Services requirements of which the provision of Frequency Control by means of Frequency sensitive generation is mandatory.

- Connection Conditions Appendix 3 specifies the minimum frequency response requirement profile and operating range for Power Stations and DC Converter Stations (with a completion date on or after specified dates).

- BC3 (Frequency Control Process) sets out the procedure for NGET to use in relation to Users to undertake System Frequency control as follows:

Grid Code Definitions

- *Primary Response*
  The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall on the basis set out in the **Ancillary Services Agreement** and fully available by the latter, and sustainable for at least a further 20 seconds. The interpretation of the **Primary Response** to a – 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2.

- *Secondary Response*
  The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be fully available by 30 seconds from the time of the start of the **Frequency** fall and be sustainable for at least a further 30 minutes. The interpretation of the **Secondary Response** to a -0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2.

- *High Frequency Response*
  An automatic reduction in **Active Power** output in response to an increase in **System Frequency** above the **Target Frequency** (or such other level of **Frequency** as may have been agreed in an **Ancillary Services Agreement**). This reduction in **Active Power** output must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the **Frequency** increase on the basis set out in the **Ancillary Services Agreement** and fully achieved within 10 seconds of the time of the start of the **Frequency** increase and it must be sustained at no lesser reduction thereafter. The interpretation of the **High Frequency Response** to a + 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.3.

- *Frequency*
  The number of alternating current cycle per second (expressed in Hertz) at which a **System** is running.

4. National Grid's Operational Standards

NGET (acting as GSBO) will manage and operate the GB Transmission system to Operational Standards as follows:

- **Application of GB Security and Quality of Supply Standards in Operational Timescales**

  Frequency Control Standard
  In seeking to meet the objective set out above, frequency under normal conditions will be maintained within operational limits of +/-0.2Hz. As a consequence, and recognising the minute to minute perturbations in both total mechanical power input and actual system demand, there will be an error between standard time and that derived electrically. An operational limit on time-error of +/-10 seconds will apply.

  To achieve this operational objective of "time" control National Grid Control will, from time to time, set target frequencies within the range +/-0.05Hz and, in exceptional circumstances, outside this range.

  It is accepted that, under fault conditions or where significant changes to foreseen operating conditions have taken place, the frequency will move outside operational limits. However, in the interests of maintaining a satisfactory level of frequency control, National Grid shall aim to limit the number of excursions outside operational limits to less than 1500 p.a., and ensure that standard deviation of 5 minute spot values of system frequency does not exceed 0.07Hz.

  In addition, sufficient MW reserves, having suitable time related capability will be held to ensure that for all SIGNIFICANT or ABNORMAL events (defined below) the following system performance is achieved:-

  ⇨ **SIGNIFICANT:** for any credible fault which could result in sudden change between total mechanical power input and actual system demand which is in the range 300MW to 1000MW the system frequency should not deviate by more than 0.5Hz. In the Security and Quality of Supply Standard this is defined as a *Normal Infeed Loss Risk*.

  ⇨ **ABNORMAL:** for any credible fault which could result in a sudden change between total mechanical power input and actual system demand which is in the range 1000MW to 1320MW the system frequency should not deviate by more than 0.8Hz. In the Security and Quality of Supply Standard this is defined as an *Infrequent Infeed Loss Risk.*

  For either significant or abnormal events any frequency deviation below 49.5Hz should not persist for more than 60 seconds, and system frequency should return to between operational limits within 10 minutes.

For all sudden imbalances between total mechanical power input and actual system electrical demand of less than 300MW, system frequency shall not deviate outside operational limits

- **Operating Margin**

Frequency Response Requirement

The Primary, Secondary and High Frequency Response required to cater for instantaneous losses is expressed as a function of the generation or demand losses being catered for and the system demand at the time.

The Total Response Requirements cater for:

⇨ Generator under performance against Response contract
⇨ Variation in initial trip frequency
⇨ Increased System Losses following the fault
⇨ Modelling Inaccuracies
⇨ ROCOF (the effect of Rate of Change of Frequency relay operation)

and to cater for (as and when necessary) periods of exceptional demand uncertainty and Emergency conditions

At higher demands the generation loss that sets the Primary Response requirement may not be the largest size of loss being covered at the time. It is possible for the total Primary Response required to contain a loss of 1000MW (or below) to be higher than for losses of a greater magnitude. This is because the frequency control standard specifies that losses of 1000MW and below must be contained to a -0.5Hz frequency deviation whereas greater losses must be contained to the larger -0.8Hz deviation.

Response is provided from a number of sources including -

⇨ Synchronised Generation through Governor action
⇨ LF relay initiated Demand Reduction
⇨ Contracted Demand Management (FCDM)
⇨ LF relay initiated Generation
⇨ Pumped Storage or Hydro Spin Generation
⇨ Contribution from Externally Interconnected System Operators

To ensure that the quality of steady state frequency control meets the targets (standard deviation < 0.07) then a minimum amount of response must be carried on Synchronised Generating Plant (Dynamic) operating under Governor action. The response that should be allocated to synchronised generating plant is therefore the maximum of the amount required to aid in the containment and recovery of instantaneous losses and that required to provide steady state (or Dynamic) frequency control:

Synch Response = MAX (Synch Response (For Instantaneous Loss), Synch Response (Dynamic))