Frequency Response - Workgroup Consultation

This workgroup consultation aims to inform parties of the work that the Frequency Response Workgroup has completed and seeks views on the proposals identified by the Workgroup. This is not a Workgroup Report but the content and views provided by parties in response to this consultation will be captured in the Workgroup Report that will be submitted to the Grid Code Review Panel (GCRP).

Published on: **18 September 2012**
Length of Consultation: **30 Business Days**
Responses by: **30 October 2012**

High Impact:
New generators and interconnectors required to provide frequency response, System Operator

Medium Impact:
Suppliers

Low Impact:
None identified

Contents

Any Questions?

Contact:

Thomas Derry

Code Administrator

Thomas.Derry@nationalgrid.com

01926 654 208

Proposer:

Frequency Response Workgroup

About this document

This document contains a summary of the discussions and findings of the Frequency Response Workgroup. It also seeks industry views on the proposals that have been developed to date.

Following the conclusion of this consultation, the Workgroup will review the responses along with finalising a report which will be submitted to the Grid Code Review Panel to take account of in formulating the next steps in this area.

The Workgroup would also like to invite interested parties to join the Frequency Response Workgroup to support further discussion and analysis. If you are interested in joining the Workgroup please contact:

Thomas Derry
Thomas.Derry@nationalgrid.com

Document Control

Version	Date	Author	Change Reference
0.1	23 February 2012	National Grid	Draft Workgroup Consultation
0.2	01 March 2012	National Grid	Draft Workgroup Consultation incorporating Workgroup comments
0.3	05 April 2012	National Grid	Draft Workgroup Consultation incorporating Workgroup comments
0.4	09 May 2012	National Grid	Draft Workgroup Consultation incorporating Workgroup comments
0.5	07 June 2012	National Grid	Draft Workgroup Consultation incorporating Workgroup comments
1.0	18 September 2012	National Grid	Final Workgroup Consultation

Executive Summary

1.1 The Frequency Response Workgroup was established to examine and make recommendations for the future provision of frequency response, taking account of system security requirements and with the aim of delivering an efficient solution for the industry as a whole.

1.2 Since the Workgroup was established in 2008, there have been 21 Workgroup meetings up to the publication of this document. Over that time a number of commercial arrangements and technical requirements have been discussed and analysed by the Workgroup.

1.3 To assess issues associated with meeting the requirements for frequency response arising from significant changes to the generation background, a Frequency Response Technical Subgroup (FRTSG) was established in November 2010. The aim of the FRTSG which was to complement and extend the technical work initiated by Frequency Response Workgroup (a joint BSSG and GCRP Workgroup), and in particular investigate issues such as the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background.

1.4 Alongside the work undertaken by the FRTSG, the Frequency Response Workgroup developed a number of commercial arrangements which aim to improve the provision of frequency response services.

1.5 This consultation document has been published by the Frequency Response Workgroup to highlight the discussions had to date and to seek industry views on the technical and commercial options developed.

1.6 If you would like to make a response to this Workgroup Consultation please use the proforma and return your response to grid.code@nationalgrid.com by 30 October 2012. Further information is available under the section 'Consultation Responses' contained within this report.

1.7 A copy of the consultation proforma can be found at:

http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/

Purpose & Scope of Workgroup

1. Background

1.1 At the May 2008 Grid Code Review Panel (GCRP), National Grid presented paper pp08/20 which proposed that a Workgroup was established to examine and make recommendations for arrangements for the provision of frequency response, taking account of system needs and overall efficiency.

1.2 The GCRP agreed that a joint CUSC and Grid Code Workgroup should be established and, following the first Workgroup meeting on 22 October 2008, the Terms of Reference were approved by the GCRP. It was agreed that the Workgroup would report to the Balancing Services Standing Group (BSSG), a standing group under the CUSC.

1.3 The joint BSSG/Grid Code Workgroup would be tasked with reviewing the technical requirements and commercial mechanisms applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

1.4 A copy of the Terms of Reference is available in Annex 1.

2. Scope

2.1 The Terms of Reference underwent a number of alterations over the time, agreed by the GCRP, that the Workgroup has been established. The current scope of the Workgroup is:

(i) examine the appropriateness of the existing Grid Code obligations and commercial mechanism for frequency response to the current and predicted future generation mix – including offshore generation;

(ii) identify feasible options that will maintain the security of the National Electricity Transmission System following frequency deviations (inclusive of islanding scenarios), taking account of the characteristics of the current and next generation of power stations e.g. nuclear, supercritical coal, wind etc and the potential for demand management;

(iii) identify and quantify the advantages and disadvantages of each option;

(iv) identify all the impacts of each option on the Grid Code, CUSC and any other associated documents within the framework;

(v) agree and recommend a preferred option;

(vi) draft any text modifications necessary to implement the recommendation;

(vii) monitor the progress of the National Electricity Transmission System SQSS review and take into account any impact on the frequency reserve holding requirement arising from its recommendations.

(viii) consider frequency response provisions of any other comparable electricity networks worldwide

(Ix) Consider the interaction with the ongoing development of the European Network Codes.

3. Timescales

3.1 It was originally agreed that the Workgroup would report its findings and recommendations to the November 2009 GCRP. As the issues around frequency response were investigated and studies conducted the original timeframe has been reviewed and agreed to allow further work to be undertaken.

3.2 It was agreed at the January 2012 GCRP that the Workgroup would report back to the November 2012 GCRP. This revised timescale was agreed to allow the Workgroup to conduct an industry consultation on the discussions and findings of the Workgroup to date.

4. Frequency Response Workgroup

4.1 Following agreement from the GCRP to establish the Frequency Response Workgroup in May 2008, the first Workgroup meeting was held on 22 October 2008.

4.2 Since the Workgroup was established in 2008, there have been 21 Workgroup meetings up to the publication of this document. Over that time a number of commercial arrangements and technical requirements have been discussed and analysed by the Workgroup.

4.3 Due to the wide ranging discussions that have taken place, the technical requirements and commercial arrangements each have their own chapter within this consultation.

5. Frequency Response Technical Subgroup

5.1 In September 2010, National Grid presented paper pp10/21 to the Grid Code Review Panel (GCRP) entitled "Future Frequency Response Services". This paper summarised the issues associated with meeting the requirements for frequency response arising from significant changes to the generation background. A copy of this paper can be found in Annex 2.

5.2 In October 2010, the Frequency Response Workgroup discussed the establishment of a Frequency Response Technical Subgroup (FRTSG) which would develop recommendations to address the issues discussed in paper pp10/21 submitted to the GCRP.

5.3 In November 2010, the FRTSG was established to complement and extend the technical work initiated by Frequency Response Workgroup, and in particular investigate issues such as the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background. The Terms of Reference for the FRTSG can be found in Annex 3.

5.4 The FRTSG had 7 meetings and during that time the Frequency Response Workgroup held limited meetings until the publication of the Technical Subgroup conclusions.

5.5 The FRTSG published their conclusions in December 2011. A copy of the Technical Subgroup conclusions can be found in Annex 4.

Timeline

Frequency Response Workgroup Meetings

M1 - 22 October 2008
M2 - 29 January 2009
M3 - 30 March 2009
M4 - 03 July 2009
M5 - 01 September 2009
M6 - 27 October 2009
M7 - 02 December 2009
M8 - 15 February 2010
M9 - 28 April 2010
M10 - 01 June 2010
M11 - 08 July 2010
M12 - 13 August 2010
M13 - 10 September 2010
M14 - 14 October 2010
M15 - 20 December 2010
M16 - 04 March 2011
M17 - 12 September 2011
M18 - 13 January 2012
M19 - 01 March 2012
M20 - 05 April 2012
M21 - 09 May 2012

Frequency Response Technical Subgroup Meetings

M1 - 15 November 2010
M2 - 03 December 2010
M3 - 13 January 2011
M4 - 28 March 2011
M5 - 05 August 2011
M6 - 13 October 2011
M7 - 07 November 2011

1.1 This chapter contains a summary of the discussion, analysis and conclusions of the FRTSG.

1.2 The Terms of Reference for the FRTSG can be found in Annex 3 and copy of the Technical Subgroup Report can be found in Annex 4.

2. Background

2.1 A major element of this study work is to establish the effect on system frequency of the increasing volume of variable speed wind turbines and HVDC Converter technology. Whilst these issues are now well known, and set out in the 'Future Frequency Response Requirements' paper (Annex 2), it is worth briefly summarising the potential concerns.

2.2 Conventional synchronous generation which currently contributes to the majority of the Transmission System load is sensitive to changes in system frequency. In the event of the loss of a generating unit, the remaining synchronous plant will supply an injection of active power into the network through the stored energy in the rotating masses. This natural phenomena greatly assists in limiting the rate at which system frequency changes.

2.3 Unfortunately, variable speed wind turbines and other static devices which utilise power electronic converters such as HVDC converters are insensitive to frequency changes and therefore do not behave in the same way as synchronous machines resulting in a diminution in the system frequency. This issue is illustrated in Figure 1 below.

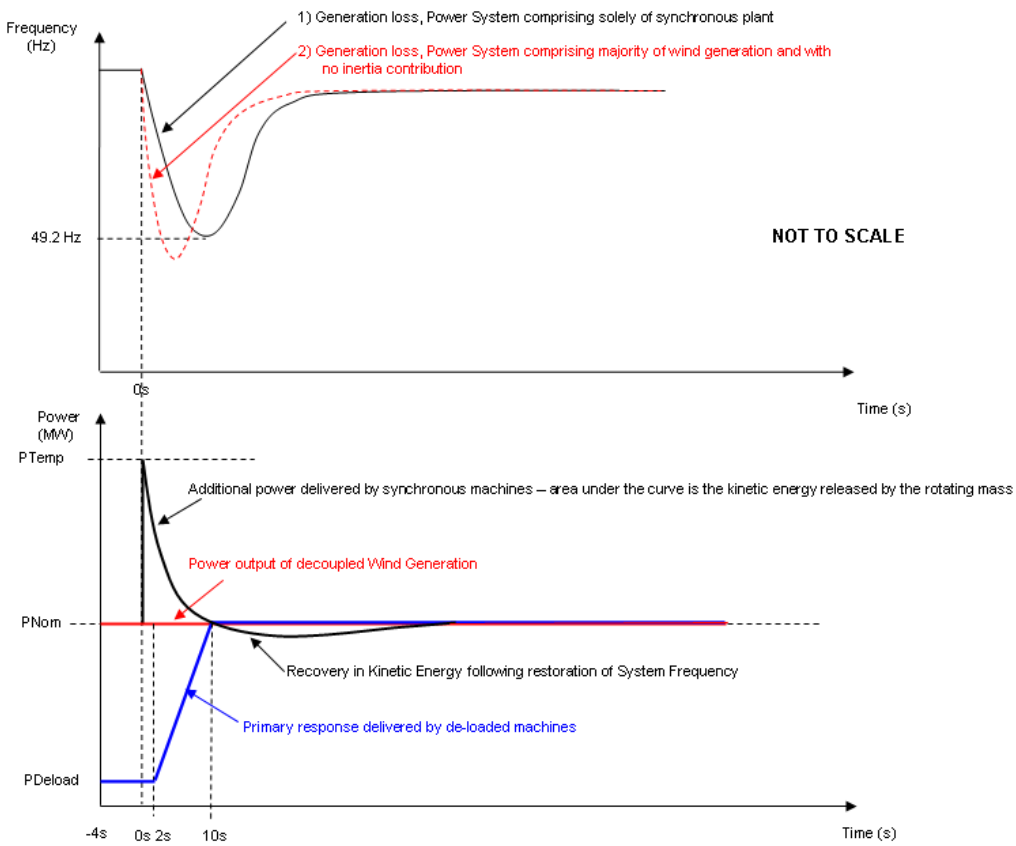


Figure 1: The effect of reduced system inertia on the management of a large infeed loss

2.4 As can be seen in the red curve of Figure 1, for the same generation loss, it is not possible to maintain the system frequency above 49.2Hz when a high volume of asynchronous generation is connected to the system and unable to contribute to system inertia. The reason for this is the lack of

Active Power (shown by the red line) injected from the asynchronous generation as shown in the lower of the two graphs in Figure 1.

3. Initial Discussion

3.1 The discussions focussed on two approaches to managing large frequency deviations on systems where a lack of 'natural' inertia means that the system frequency may not be contained within statutory and technical limits.

3.2 The first approach considered was to investigate the option of equipping variable speed wind turbines and other asynchronous sources with a ‘synthetic inertia’ capability. This capability has the potential to improve frequency control without needing to curtail the power output of the wind turbine generating units prefault. This option was investigated at length and detailed discussions were held with a number of the major wind turbine manufacturers.

3.3 A number of manufacturers have indicated an ability to provide a synthetic inertia capability and have published papers and information on their capabilities - see references [1] – [4] in Annex 5. These controllers aim to inject power to the network in a similar way to that of a synchronous machine, but through controlled action.

3.4 As part of an effective control strategy, it is important to ensure sufficient active power is injected into the network to balance the loss of generation. Clearly too much active power injected into the network could result in temporary over frequencies occurring before governor action provides adequate downward regulation. For example, with a loss of generation of less than 300MW, only a small amount of active power would be required where as a larger injection would be required for the maximum loss of 1,800MW.

3.5 A good measure of the required level of active power injection can be obtained from a measure of the rate of change of system frequency (df/dt) (ie the smaller the value of df/dt the lower the initial injection of active power required).

3.6 National Grid modelled two controllers both using df/dt functionality. One was based on an initial injection and fixed decay based on the rate of change of system frequency. The second was based on a continuously acting df/dt controller which would operate throughout the entire disturbance, and in doing so regulating the active power injection to the network continuously. Based on the results, both controllers were able to inject sufficient active power to the network to ensure the maintenance of system frequency above Security and Quality of Supply Standards (SQSS) limits. These are described in more detail in Annex 5.

3.7 Whilst system studies confirmed that both controllers could be used as a basis to resolve the issue of retaining frequency standards, further discussion identified two critical issues. These being:

- df/dt controllers are noise amplifying and can, even with appropriate filtering, fail to operate in the appropriate manner, particularly where small time constants are involved; and
- the recovery period for wind turbines operating at just below rated wind speed can result in substantial reductions in their active power output, resulting in a system frequency collapse some 10 to 15 seconds after the initial generation loss.

3.8 With regard to the df/dt issue, National Grid held extensive discussions with manufactures to examine the df/dt controller and how it could be improved. National Grid amended their own models and identified that even with slower response times the controller could still aid frequency containment.

3.9 It was also suggested that the controller should not only rely on a df/dt input but should also incorporate a frequency trigger. Consideration was also given to a simple 'one-shot' control which would deliver a fixed volume of energy with a defined ramp and decay period when frequency reached a pre-defined setting.

3.10 A benefit of the 'one-shot' control is that it is less complex than a df/dt trigger. However, it wouldn't adapt to a specific frequency event after the initial frequency disturbance, potentially resulting in an uncontrolled response.

3.11 With regard to recovery periods, concerns were raised relating to the potential reduction in power output from wind turbines following the provision of increased active power output in response to a frequency fall.

3.12 A variable speed wind turbine relies on operating at the optimum power output for a given wind speed to extract the maximum available power from the wind. This is a complex non linear function and becomes a significant issue when the wind turbine is operating just below rated wind speed. In the event that the wind turbines are operating at just below their rated wind speed and activation of the synthetic inertia control is required, then once the additional active power has been injected into the network, the recovery period can result in a drop in power output of up to 30% of its pre fault output, resulting in a frequency collapse after the event.

3.13 Figure 2 below shows an illustrative frequency trace using a power injection equivalent to 10% of non-responsive wind generation, with a 10% loss of output from the same plant after 10 seconds.

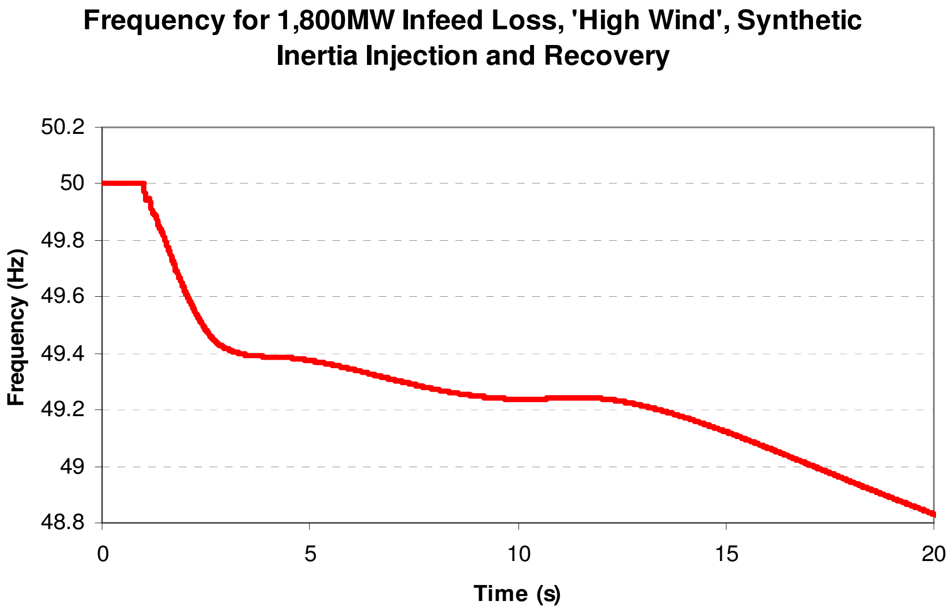


Figure 2: The effect of loss of active power output during the wind turbine 'recovery period'

3.14 In investigating this issue, a range of wind statistics were examined to determine the likelihood of a large volume of wind generation across the country operating at a similar wind speed. Data was also obtained to examine the effect of how wind speed varied within the wind farm.

3.15 The results of this analysis demonstrated that there was potentially a serious risk that a significant volume of geographically dispersed generation could be operating at a similar wind speed. The only guaranteed solution to this would be for the wind generation to be curtailed pre-fault, reducing the rate at which emission savings can be delivered.

3.16 An alternative approach to a synthetic inertia requirement would be to consider a method of rapidly injecting active power into the system following the loss of a generating unit by adopting a conventional proportional governor control.

3.17 This second approach was investigated using a response characteristic on frequency responsive wind generation that provided full primary frequency response within 5 seconds, being sustained for a further 25 seconds, rather than the current Grid Code requirement of delivery in 10 seconds and sustainable for a further 20 seconds.

3.18 The results of these studies demonstrated that the system frequency deviations could also be contained when 'Fast Frequency Response' was installed and that significant reductions in response requirements could also be achieved.

3.19 Discussions also highlighted concerns over the ability to deliver a synthetic inertia capability and conventional Primary Response from the same machines at the same time. It is therefore necessary to consider the likely generation patterns more carefully to check whether there is a sufficient amount of synthetic inertia capable plant which isn't already required to manage system frequency in Primary and Secondary response timescales.

3.20 In assessing the materiality of the issue, it is also important to consider the proportion of the time where a synthetic inertia requirement may be needed to allow National Grid to meet the frequency containment requirements of the SQSS. Initial simulations highlighted that achieving frequency containment was significantly more challenging at transmission system demands of 35GW and less. A review of transmission system demands for 2008 to 2010 suggests that this represents approximately 50% of the time.

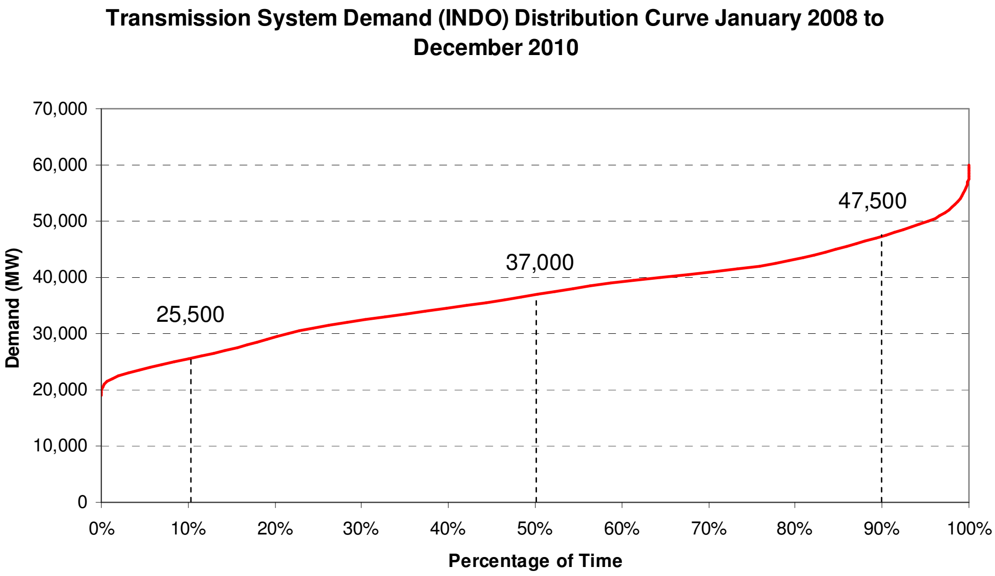


Figure 3: Transmission System Demand distribution curve

3.21 The next stage of analysis therefore needed to be based on clear demand and generation assumptions which are discussed in the full version of the Technical Subgroup Report (Annex 4).

4. Conclusions

4.1 In order to manage the Transmission System in the future and ensure system frequency can be managed to the criteria set out in the SQSS, there will be a requirement to mitigate the reduced contribution to system inertia from decoupled generation plants such as variable speed wind turbines and other static plant such as HVDC Converters.

4.2 The following conclusions were drawn from National Grid's simulations based on a 'Gone Green' generation scenario for the year 2020:

- A supplementary frequency control facility can deliver significant benefits in managing the 1,800MW and 1,320MW infeed risk at system demand levels of 35GW and below under all but "Low Wind" conditions.

- The measures needed to ensure compliance with the SQSS, and avoid impacting on system security, become more severe and more significant in volume as system demand, and the capacity of any synchronous generation meeting it, decreases;

- Additional low frequency relay triggered demand response was required as well as supplementary frequency control capability to achieve frequency containment at system demands of 20GW under 'High Wind' conditions;

- These factors suggest that both a supplementary frequency control capability and alternative actions will be required to ensure frequency containment can be achieved at demands of less than 25GW. Further alternative actions include:

  (1) Curtailment of the largest infeed loss; and

  (2) Additional balancing actions, such as:

    (2a) curtailment of interconnectors or inflexible plant;

    (2b) displacement using plant with additional response capability;

    (2c) fast acting low frequency relay triggered response; and

    (2d) addition of inertia, by 'low load operation' on synchronous generation for example.

4.3 It should be noted that the simulations were based on an interconnector position of 'float' (ie no import/export) and that any net interconnector import has the effect of displacing synchronous plant. There is currently 3.5 GW of interconnector capacity on the transmission system, a variability of 7GW. It should however be noted that the volume of interconnections to Great Britain may increase in the future.

4.4 A number of supplementary frequency control capability options were investigated, including a pure 'df/dt' driven fast acting control on un-curtailed asynchronous plant which is intended to mimic the inertia capability of a synchronous machine. This form of control provides an ideal solution, as it helps solve the frequency control problem without the need to curtail wind. However, there are a number of issues associated with it:

- any control system will incorporate a processing delay which needs to be limited to ensure the desired effect is achieved;

- Rate of Change of Frequency (RoCoF) as an input parameter is inherently noise amplifying leading to unpredictability of response;

- care needs to be taken not to extract too much energy from wind turbines as this can lead to an extended and detrimental recovery period, particularly at specific points on the wind turbine operating curve. This leads to some uncertainty over the volume and timescales of energy available; and

- discussions suggest that wind based Power Park Modules will find it difficult to deliver both a 'df/dt' driven fast acting control and Primary Response consecutively with the volumes required. This issue is critical as work to date suggests that both are required under most of the relevant system scenarios.

4.5 Alternative synthetic inertia controllers based on Rate of Change of Frequency, using fixed and variable volumes were investigated. It was demonstrated that these options provided a potential solution to the frequency containment problem, provided that the correct volumes and characteristics could be specified. These would need to be validated for the full range of possible future system conditions.

4.6 Finally, the option of using faster acting proportional frequency control was investigated by taking a conventional Primary Response characteristic and adapting it to deliver response within 5 seconds rather than 10. This characteristic was applied to wind generation which was already curtailed in order to provide conventional Primary Response within the simulations described in the Technical Subgroup Report.

4.7 This faster acting capability had the effect of reducing the Primary Response requirement and hence the need to curtail renewable generation significantly. A benefit of between 400MW and 950MW was observed in the simulations presented in the Technical Subgroup Report. If one assumes that this benefit applies for 10% of the year at an average of 500MW and response price of 30 £/MW/h, a benefit of £13m per year in balancing cost could be attributed to this capability. There would be an additional carbon benefit for the wind curtailment avoided.

4.8 Based on the analysis conducted, it has been concluded by the Technical Subgroup that the single change to response provision that would yield the most significant benefit is through the introduction of a fast primary frequency response capability applicable to all decoupled generation sources which do not naturally provide an inertial contribution.

4.9 Such generating plant should have the capability to provide 10% or more of its registered capacity as primary frequency response which should be delivered linearly over a 5 second period from the inception of the generation loss or load change and an initial delay of no more than 1 second from the inception of the frequency change.

4.10 It is recognised that this specification may present a challenge to technology providers and manufacturers. However, it is believed that this specification is more achievable, at an earlier implementation date, than the df/dt triggered control option discussed above.

4.11 Simulations also showed a high degree of sensitivity to the ramp rate assumptions for Primary Response. It is recommended that these are specified explicitly within the Grid Code by setting out a maximum response delay of 1 second and specifying that response should be delivered linearly up to 10 seconds or 5 seconds as appropriate.

4.12 Whilst it is acknowledged that these proposals could resolve the issue for Plant in excess of 50MW, some consideration will still be required as to how this issue will be addressed in respect of Small Embedded Power Stations as this segment of the market is expected to grow in the future.

4.13 The studies have also demonstrated the effect on rate of change of system frequency against a credible set of future generating scenarios. As a conclusion it is seen that this will impact on Embedded Generation, in particular the effect on protection settings. It is therefore suggested that the Technical Subgroup Report is highlighted to the Distribution Code Review Panel for further consideration in respect of Embedded Generation.

4.14 A final point to note is the extent of reliance on wind generation to deliver frequency control in the analysis performed in the Technical Subgroup Report. Operators have little experience of this to date and it may be necessary to revisit the technical and commercial arrangements for the provisions of frequency response for asynchronous generators as more experience is gained.

4.15 Annex 7 contains text which sets out the very high level principles in addressing the need for a fast frequency response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency. The text has been drafted in the style of Grid Code change for illustrative purposes only.

5. Recommendations

Faster Frequency Response

5.1 Faster frequency response capability for asynchronous plant delivered within 5 seconds, for low and high frequencies, on users bound by the provisions of the Grid Code allows frequency response volumes to be reduced significantly in the situations analysed in the Frequency Response Technical Subgroup Report.

(a) The value of faster frequency response should be assessed by Frequency Response Workgroup, taking into consideration the costs of implementation and the benefits in reduced curtailment of generation from renewable sources and other balancing costs; and

(b) Subject to this assessment, proposals should be developed for the appropriate obligations and/or market arrangements to ensure sufficient frequency response capability is available to maintain system security for anticipated future generation and demand patterns.

Clearer Primary Response Requirements

5.2 The simulations conducted by the Frequency Response Technical Subgroup have demonstrated the sensitivity of frequency response requirements to the ramping capability of responsive generation. The Grid Code requirements for frequency response should be reviewed with the aim of clarifying the ramping capability required from responsive generation in terms of:

(a) adequacy of information provided on performance; and

(b) the need to stipulate minimum delay times and ramping capability for new providers.

Rate of Change of Frequency

5.3 The simulations performed by the Frequency Response Technical Subgroup give some indication to the potential change in the maximum Rate of Change of Frequency settings which needs to be considered in the context of the loss of mains protection deployed on embedded generation.

5.4 ***Consultation Question 1:*** Do you agree with the recommendations of the Frequency Response Technical Subgroup?

- Requirement for Faster Frequency Response on asynchronous plant?
- Clearer Primary Response Requirements for synchronous plant?

5.5 ***Consultation Question 2:*** Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

5.6 ***Consultation Question 3:*** Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

5.7 ***Consultation Question 4:*** Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

5.8 ***Consultation Question 5:*** Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?

1. Current Frequency Response Services

1.1 The Workgroup began their examination of the frequency response commercial arrangements by considering the current obligations. These obligations can be found in:

- Statutory obligations[1];
- Security and Quality of Supply Standards (SQSS) obligations[2];
- Grid Code obligations[3]; and
- National Grid's Operational Standards.

1.2 System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. It is the role of National Grid as National Electricity Transmission System Operator to ensure that system frequency is maintained as close to 50Hz as possible whilst taking into account the operational and statutory limits. In exceptional circumstances the frequency may deviate outside of the statutory limits. Figure 4 below summarises the operational and statutory frequency limits.

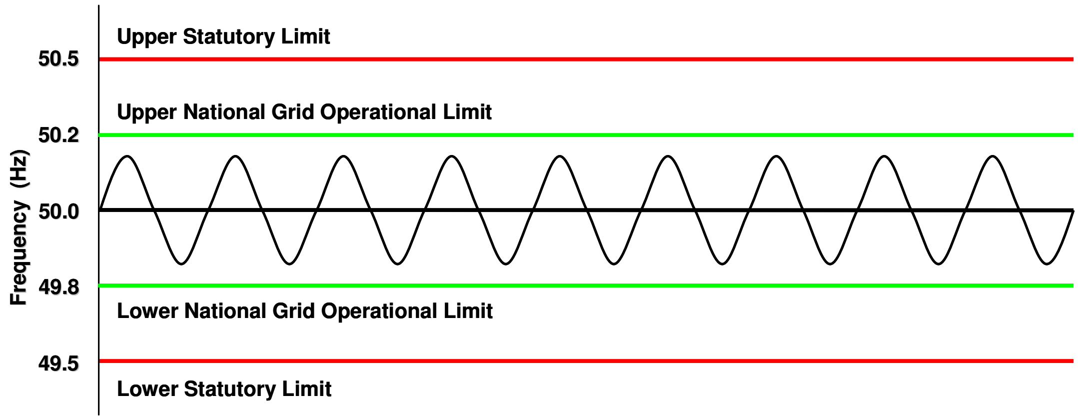


Figure 4 - Frequency Limits

1.3 As demand and generation fluctuate so to does the system frequency. If demand on the system is greater than generation, the system frequency falls while if generation is greater than demand the system frequency rises. In order to manage system frequency the System Operator primarily relies on frequency response.

1.4 There are two types of Frequency response; dynamic and non-dynamic.

- Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system.
- Non-dynamic frequency response is usually a discrete service triggered at a defined frequency deviation.

1 The Electricity Safety, Quality and Continuity Regulations 2002 http://www.legislation.gov.uk/uksi/2002/2665/contents/made

2 NETS SQSS Issue 2.2 http://www.nationalgrid.com/NR/rdonlyres/5C1E8E34-B655-4D46-B9AF-EF6EE91B12B2/52026/NETSSQSSversion22FINALchangesremoved.pdf

3 The Grid Code http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/gridcodedocs/

1.5 Frequency response is procured by National Grid through one of three contract forms:

- Mandatory Frequency Response (MFR);
- Firm Frequency Response (FFR);
- Frequency Control by Demand Management (FCDM).

Mandatory Frequency Response (MFR)

1.6 MFR is an automatic change in active power output in dynamic response to a frequency change and it is an obligation for all generators that meet the requirements of the Grid Code (CC.6.3.7, CC Appendix 3) to have the capability to provide MFR. Having the 'capability' to provide frequency response refers to the ability to provide frequency response without the physical delivery of energy whereas 'delivery' is the physical delivery of energy on to the National Electricity Transmission System (NETS) used for frequency response.

1.7 The capability to provide MFR is a condition of connection for generators connecting to the NETS. MFR is not applicable for non-Balancing Mechanism Unit (BMU) or demand providers.

1.8 The current Grid Code obligation, illustrated below in figure 5 and 6, requires that a generation unit with a Completion Date after 1st January 2001 must provide:

- primary response (within 10 seconds, sustainable for 30 seconds);
- secondary response (within 30 seconds; sustainable for 30 minutes); and
- high frequency response (within 10 seconds, sustainable thereafter).

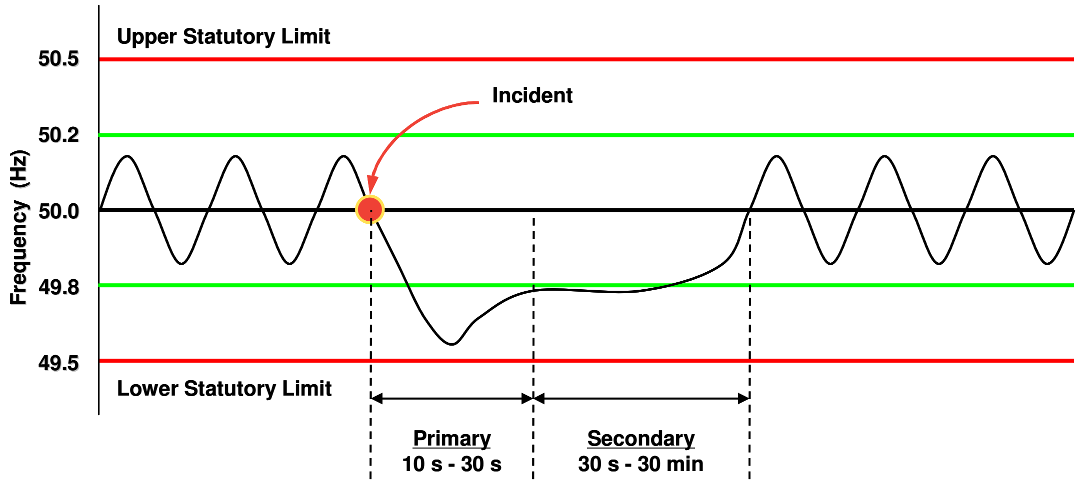


Figure 5 - Primary and Secondary Response

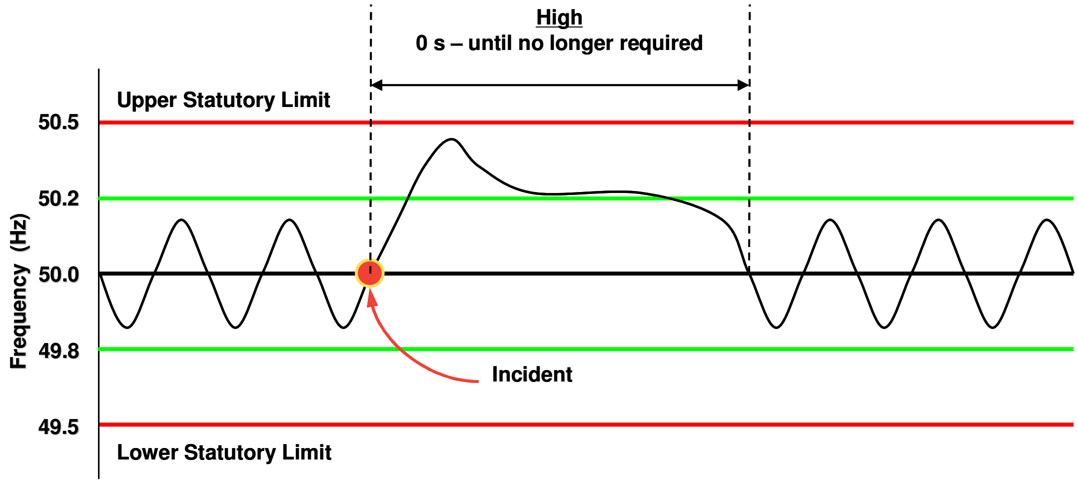


Figure 6 - High Response

1.9 The level of response for primary, secondary and high is 10% of a User's Registered Capacity (subject to operating level) and this can be found in figure CC.A.3.1 of the Grid Code.

1.10 MFR makes up the majority of the procured volumes and costs for frequency response. There are four main cost elements associated with procuring MFR:

- holding costs (based on capability prices submitted by the provider monthly for primary, secondary and high) which are payments made to the provider, by NGET as System Operator, to cover the costs when the provider is selected to provide response;
- energy costs which are payments made to the provider, by NGET as System Operator, to remunerate them the amount of energy delivered when providing frequency response;
- generator positioning costs, generally Bid-Offer Acceptance (BOA) costs, which are incurred in changing the generation output to enable response energy to be provided; and
- imbalance volumes which are caused by the delivery of response energy and offset by Applicable Balancing Services Volume Data (ABSVD)[4].

1.11 Once a new generating unit is built (or modified), National Grid must test its response capabilities to ensure the generating unit meets the minimum Grid Code requirements. Following successful assessment by National Grid, a Mandatory Service Agreement (MSA) as required under the CUSC is put in place (or amended), which allows National Grid to instruct the service when it is needed. Additionally, once an MSA is signed, National Grid adds the generator to the Frequency Response Price Submission (FRPS) system.

1.12 The FRPS system is a web based service that allows MFR providers to submit holding prices per MWh of primary, secondary and high response products on a monthly basis. After setup is complete, prices can be entered in to the system during the 5th and 15th Business day of each month applicable for the following month. Bid and Offer prices are entered into the Balancing Mechanism in line with the Grid Code requirements.

[4] ABSVD Methodology Statement http://www.nationalgrid.com/NR/rdonlyres/77770247-3E35-4842-B976-BEDEEAB67297/46017/ABSVDv3_April2011.pdf

Firm Frequency Response (FFR)

1.13 FFR is a form of commercial frequency response that is designed to compliment other sources of frequency response and delivers firm provision of Dynamic or Non-Dynamic Response to changes in Frequency.

1.14 National Grid procures FFR to manage the same incidents as MFR but unlike MFR, FFR is open to BMU and non-BMU providers, existing MFR providers and new providers alike.

1.15 The FFR service creates a route to market for providers whose services may otherwise be inaccessible whilst giving both National Grid and service providers a degree of stability against price uncertainty under the MSAs.

1.16 National Grid procures FFR through a monthly tender process. Once service providers successfully complete a pre-qualification assessment and sign onto a framework agreement, they can participate in the tender process. They can tender in for a single month or multi-months. Having considered the quality, quantity and the nature of the services, National Grid will accept the most economical tender. A successful tender then becomes contractually binding.

Frequency Control by Demand Management (FCDM)

1.17 FCDM provides non-dynamic frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. The demand customers who provide the service are prepared for their demand to be interrupted for 30 minutes. Interruptions are likely to occur between approximately ten to thirty times per annum depending on the frequency set point.

1.18 FCDM is required to manage large deviations in frequency which can be caused by, for example, the loss of significantly large generation. The service is a route to market for demand-side providers, and compliments other non-dynamic service provisions.

1.19 Due to the bespoke nature of service provision, this service is provided through bilateral negotiations with providers. National Grid provides FCDM computer equipment, tests and commissions once the provider has installed the Tripping Relay Equipment and Communication Router. Once testing has been completed, a provider can join the scheme subject to signing the FCDM Ancillary Service Agreement.

1.20 Once a provider has agreed terms they are required to declare availability for each Settlement Period on a weekly basis. National Grid then will determine whether to accept this availability.

1.21 For each site where availability has been accepted by National Grid in a Settlement Period, an Availability Fee (£/MW/h) is paid against the Metered Demand in the Settlement Period of the site specified in the Agreement.

2. Workgroup Discussions

2.1 The Workgroup noted the work undertaken by the Frequency Response Technical Subgroup and their recommendations. It was agreed that appropriate commercial arrangements should be put in place to facilitate the provision of frequency response in the context of the technical conclusions.

2.2 The Frequency Response Workgroup concentrated discussion on the MFR provision and how this could be altered to facilitate improved frequency response in the future.

2.3 The Workgroup agreed that any arrangements would need to give suitable investment signals far enough in advance in order to be effective. It was also agreed that the obligations around frequency response, be they increased, maintained, reduced or removed, need to be clearly stated and defined within the Grid Code to give manufacturers clear requirements and Users confidence in the arrangements.

2.4 As the current MFR requirement is for Generators to have the capability, rather than the delivery, it is conceivable that a Generator will never be called upon for the physical delivery of energy if the System Operator can find the necessary response required at a more cost effective price.

2.5 Workgroup Members highlighted that the current MFR requirement for Generators may not be the most efficient method for ensuring the appropriate amount of frequency response is available to the System Operator and could lead to inefficient investment in capability.

2.6 Following the examination of existing frequency response obligations, the Workgroup discussed a number of high level options which have been summarised diagrammatically on the next page.

2.7 The Workgroup considered each option at a high level before determining if there was merit in giving it further consideration. Although not all of the options have progressed passed initial discussions, Sections 3 to 10 of this Workgroup Report describe each of the eight options and contain any additional analysis that the Workgroup undertook.

2.8 The Workgroup has not drawn out the status quo as an option above as these are presented as potential alternatives to the current arrangements. If an alternative is not developed the current arrangements will remain in place.

Frequency Response Services

- Mandatory Frequency Response (MFR)
  - Minimum capability obligation on Generators which is:
    - **Option A) Tradable with other providers -** A MFR obligation would be set for each generator but the capability and delivery could be traded with other providers to meet the obligation
    - **Option B) Shared onsite -** A MFR obligation would be set for each generator but the capability and delivery could be traded to other onsite providers
    - **Option C) Based on company portfolio -** A MFR obligation would be set based on a company portfolio and any mix of plant within the portfolio could be used to meet the obligation (i.e. more responsive units offsetting less responsive units)
    - **Option D) Based on generating technology -** A MFR obligation would be set based on the inherent technical ability of the generation technology to provide frequency response
    - **Option E) Supported with incentives -** A MFR obligation would be set and generators that do not meet the obligation would be penalised while generators which exceed the obligation would be rewarded
  - **Option F) System Operator provides response -** A MFR obligation would be removed from Generators and the System Operator would procure from providers or possibly develop and own frequency response equipment
  - **Option G) Day Ahead Auction -** Providers would submit frequency response prices from which the System Operator would procure the required level of frequency response for an operational day. This option could work with or without a MFR obligation
  - **Option H) Minimum obligation for Supplier -** A MFR obligation would be set for each supplier based on their demand requirements which could be met via procurement or provision of demand management.
- Firm Frequency Response (FFR)
- Frequency Control by Demand Management (FCDM)

3. Option A - Minimum capability obligation which is tradable with other providers

3.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but a generator would be able to trade away provision of that capability to other plant (which would still need to be capable of providing its own MFR requirement in addition). For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds

- Under Option A, Generator X can contract with Generator Y for their additional 4% of primary response and both generators would be able to meet their primary response obligation.

3.2 This option would not preclude contracting with other providers of frequency response (e.g. demand providers) and would allow a generator to contract with other providers located across the National Electricity Transmission System (NETS) to provide additional response.

3.3 The Workgroup noted the following aspects that would need to be considered as part of Option A:

- all generators and their contracted providers would need to be tested;

- all generators and providers would need to have adequate metering installed to be able to monitor response energy delivery;

- all providers would need to be able to be selected to provide response at any time;

- arrangements would need to ensure that there was capability contract price discovery to enable efficient generator investment decisions to be made; and

- the point at which National Grid steps in to manage frequency response if a contracted provider does not deliver.

3.4 It was recognised that existing plant would have to meet the requirements of the Grid Code of their day and would not be required to meet requirements subsequently introduced into the Grid Code. The Workgroup also noted that under this option, generators that cannot meet their frequency response obligations could meet their obligation through contracting and should therefore not require a derogation.

3.5 The Workgroup agreed that Option A merited further discussion and consideration.

Impact on Operational Costs

3.6 The implementation of the arrangements as outlined above could have a number of impacts on operational costs. The outcome will depend on the contracting strategy of each generating unit, the generation technology that is providing the additional response and the operational period (i.e. level of demand).

3.7 There could be a situation in which less-responsive generation is running that cannot meet the overall response requirements. Therefore, a reduction in less-responsive generation (generation not compliant with the Grid Code) would be required to provide room for a corresponding increase in more-responsive generation and would lead to higher operational costs.

3.8 Alternatively, there could be a situation in which more-responsive generation is running that can meet more than the overall response requirements. Therefore, a reduction in less-responsive generation is not required to make room for more-responsive generation and would likely lead to lower operational costs.

3.9 Providers of additional response may have additional MW that they could provide to the energy market when the primary unit they have contracted with is not running. This could help providers to recover the cost of investment in a shorter period of time.

3.10 If each unit which does not or cannot meet the current mandatory requirement contracts with alternative technology, then it is likely that costs will be maintained or slightly increase. It is generally believed that the cost of new technology will be higher than the current costs of response. Therefore, if a generator is contracting with new technology, it is anticipated that this will be more expensive than the current cost levels. Although it is recognised that over time it may become cheaper to contract with alternative technology as it becomes more established.

3.11 It also needs to be noted that if the scenario materialises where the contracted unit fails to deliver the required response on behalf of the non-complaint generator it could lead to increased operational costs. The Workgroup assumes that the commercial ramifications that materialise from failure to deliver would be managed appropriately through the bilateral agreement between the generator and their provider of additional response.

Impact on Generation Investment Costs

3.12 It is anticipated with the ability to trade capability that generation investment costs could decrease as generators would not be required to invest in being able to provide frequency response capability themselves where it was less efficient to do so. Generators could contract with a provider who could provide the generators frequency response requirement more efficiently and at a lower cost.

3.13 These lower investment costs could be reflected in lower power prices although it should be noted that these requirements are forward looking and depending on the obligation, generation investment costs would vary.

Potential Cost Benefit

3.14 It would be anticipated that more efficient generation investment would lead to a decrease in the price of power. Quantifying this is difficult to do and relies on an understanding of how the market will operate with large amounts of variable generation, market behaviour and management of large portfolios.

3.15 Depending on the factors highlighted above, lower or higher operational costs could result in a corresponding change in Balancing Services Use of System (BSUoS) costs. Currently all BSUoS costs are socialised across all system users during each half hour. The Workgroup is aware of the recent approval of CMP202 which has removed BSUoS charges for lead parties of Interconnector BM Units[5] and the ongoing CMP201 which seeks to remove BSUoS charges from Generation[6].

3.16 If BSUoS costs increased it is difficult to know if they would be offset by lower power prices through efficient generation investment. Although, increases in BSUoS costs would provide some incentive on system users to provide response during periods of high costs (high costs caused by response provision).

3.17 Alternatively, if BSUoS costs decreased and lower power prices were seen through efficient generation investment an overall cost reduction could be seen which could translate into lower prices for consumers.

3.18 It also needs to be noted that if the scenario materialises where the contracted unit fails to deliver the required response it could lead to increased operational and BSUoS costs.

Benefits of Option A

3.19 There are a number of benefits that can be identified:

- promotes development of and facilitates access for alternative generation technologies that may not be able to meet current Grid Code requirements;
- maintains system security risk to current levels;
- provides flexibility in the provision of response volumes for mandatory providers;
- potential for lower power prices, and lower operational and BSUoS costs;
- additional frequency response and MW available when alternative response provider is running and main plant is not; and
- if the market size increases, existing sites may add on-site technology to increase their frequency response ability to contract out.

Disadvantages of Option A

3.20 There are a number of disadvantages that can be identified:

- any outage on the additional response provider technology would mean primary generator could not meets its obligation;
- operating and BSUoS costs could increase;
- additional testing and approving of alternative technologies would be required;
- need to improve metering of response volumes provided;
- increased optimisation complexity;

[5]CMP202 Decision Letter - http://www.nationalgrid.com/NR/rdonlyres/6030B915-F3E0-4418-BF08-CA6B1CC5C4BD/55635/CMP202D.pdf

[6] CMP201 Code Administrator Consultation - http://www.nationalgrid.com/NR/rdonlyres/DDF09C57-F559-4F3D-91D6-11070D3DDF93/55346/CMP201CodeAdministratorConsultation.pdf

- increased interaction with the energy market;

- increased monitoring of contracts and publication of contract information; and

- depending on the plant providing the additional response, investment savings could translate into operational costs.

3.21 ***Consultation Question 6:*** Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.

3.22 ***Consultation Question 7:*** Is there anything additional you wish to note regarding Option A?

4. Option B - Grid Code Obligation with the Ability to Share Obligation On-site

4.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but they would be able meet any shortfall in response capability through the use of on-site alternative technologies such as batteries or flywheels. For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- To address the 4% primary response deficit, Generator X develops additional on-site technology that can produce at least 4% primary frequency response.

4.2 The Workgroup did not believe that having the alterative technology based on-site would preclude another party from owning and operating it.

4.3 The Workgroup agreed that Option B merited further discussion and consideration.

Impact on Operational Costs

4.4 As all generators will be compliant with the Grid Code (via self provision or alternative on-site response technology), costs should be similar to current levels (dependent on the cost of new technologies in providing the additional response volumes).

4.5 As the additional on-site technologies may also be available to provide response when the corresponding generation is not available, costs could decrease as there could be more response volume available to the System Operator.

4.6 A scenario could occur in which the primary plant is not running but enough additional on-site response is available that it would prevent the need to deload less-responsive generators elsewhere on the system.

4.7 Another scenario could materialise where the contracted alternative on-site response unit fails to deliver the required response on behalf of the non-compliant generator which could lead to increased operational costs.

Impact on Generation Investment Costs

4.8 Option B allows a generator to determine the most cost effective manner in determining how they meet their Grid Code frequency response obligations i.e. rather than invest in generation, the investment may be more efficiently provided via alternative technology.

4.9 However, there could be increased investment required from a generator to install alternative technologies in addition to their primary unit. There could also be costs associated with gaining the necessary experience depending on the technology employed.

4.10 These costs may be offset by the savings in not having to ensure their primary unit is able to provide their entire obligation.

4.11 Alternative on-site technology could increase the entry capacity required for the site and the additional on-site unit could provide MW to the energy market rather than solely provide frequency response. Whilst a higher entry capacity might result in different Grid Code obligations that need to be met, additional MW available for the energy market may hasten the return on investment. The generator would have to determine the best deployment of MW which is the same as the current arrangements when operating at peak load.

4.12 There is the potential that it is more expensive to provide the additional response technology on-site rather than at other sites.

Potential Cost Benefit

4.13 Initial discussions indicate that there could be lower operational and generation costs which could translate into lower costs passed on to the consumer.

4.14 Arguably a generator will determine the most cost effective way to meet their Grid Code response obligations which could result in lower operational costs compared to the current arrangements. Additional on-site capacity could also result in more MW available in the energy market leading to lower power prices.

4.15 The Workgroup also recognised that if the additional on-site response was a storage based technology it could be used to smooth out intermittent generation which could reduce BSUoS costs.

Benefits of Option B

4.16 There are a number of benefits that can be identified:

- promotes development of and facilitates access for alternative generation technologies that may not be able to meet current Grid Code requirements;
- maintains system security risk to current levels;
- provides flexibility in the provision of response volumes for mandatory providers;
- potential for lower power prices, and lower operational and BSUoS costs;
- unlike Option A there is no requirement to provide additional metering as the provision of response is provided at the generation site;
- unlike Option A there would not need to be additional monitoring of response volumes;
- optimisation would be of a similar complexity to current arrangements;
- unlike Option A there would likely be lower interaction with the energy markets and no need to monitor and publish response contracts; and

- additional frequency response and MW available when additional response unit is running and main plant is not,

Disadvantages of Option B

4.17 There are a number of disadvantages that can be identified:

- any outage on the alternative technology would mean generator could not meets its obligation;
- increased generation investment costs;
- reliability risks associated with new technology;
- limits the technologies that would be available to provide response (i.e. demand side providers would not be able to provide on-site response);
- saturation of the market by having sites meeting the frequency response requirements;
- likely to be most effective capital solution but not necessarily most overall effective solution; and
- it could be more expensive to provide the technology on-site rather than at other sites.

4.18 ***Consultation Question 8:*** Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.

4.19 ***Consultation Question 9:*** Is there anything additional you wish to note regarding Option B?

5. Option C - Minimum capability obligation which is based on company portfolio

5.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but the requirement would be set based on the company portfolio. The generator would then choose how to meet their obligation with units from the portfolio. For example:

- A generator has two power stations within their portfolio, Station X and Station Y. Using the current primary response obligations, the portfolio has to be able to deliver 10% of Registered Capacity in 10 seconds.
- Station X, a new non-compliant station, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds
- Station Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds
- Under Option C, the generator can use the additional 4% of primary response from Station Y to offset Station X which would meet the primary response obligations placed on the portfolio.

5.2 As the obligation would be set on the company portfolio it would allow a generator to determine the most efficient way to meet their obligations using the plant within their portfolio. This flexibility would allow a generator to have more responsive plant offset less responsive plant rather than having each generator meet a minimum requirement. It was thought that by allowing the obligation to be met across a portfolio it would save on capital costs for future projects.

5.3 The Workgroup agreed that a portfolio could contain one unit or a number of units but noted that when a company acquires new units their frequency response requirements would alter. A frequency response obligation that fluctuates based on a company portfolio would likely be difficult and costly to monitor whilst causing operational uncertainty for the System Operator.

5.4 It was also recognised that while Option C might afford more flexibility to those generators with large portfolios, it would not permit any additional flexibility for generators with a single station that are required to provide frequency response. The Workgroup agreed that any option would need to give equal flexibility to all generators and not just those with large portfolios.

5.5 The Workgroup recognised the parallels that Option C had with other options, namely A and B, and agreed that there was no discernable benefit to Option C over other options. The Workgroup therefore determined that Option C should not be progressed any further.

5.6 ***Consultation Question 10:*** Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.

5.7 ***Consultation Question 11:*** Is there anything additional you wish to note regarding Option C?

6. Option D - Minimum capability obligation which is based on generating technology

6.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but the requirement would be set based on the technology utilised. For example:

- Generator X, a Combined Cycle Gas Turbine (CCGT), has a Registered Capacity of 100MW and, based on the inherent technical ability of the this generating technology, can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, a Pumped Storage Hydro facility, also has a Registered Capacity of 100MW and, based on the inherent technical ability of the this generating technology, can provide 14% of primary response in 10 seconds

- Under Option D, the combination of Generator X and Generator Y results in the System Operator having the required amount of primary frequency response (based on the existing requirement)

6.2 It was recognised that allowing each technology to provide a level of frequency response best suited to it might be the most cost effective option as it would not put expensive and uneconomical requirements on generators. This could result in significant capital cost savings for generators which could lead to lower power prices.

6.3 It was also understood that whilst Option D could lead to lower capital costs there could be an increase in BSUoS costs. If the mix of generation on the system put the System Operator short of the required level of frequency response for the operational day, it could mean that less economic actions need to be taken to account for the shortfall in available frequency response.

6.4 It was also questioned how each generating technology would be assessed to determine a minimum level of response. The Workgroup believed that this would come from manufacturers or testing as part of the compliance process.

6.5 The Workgroup agreed that whilst Option D could be the most cost effective option in terms of the provision of frequency response by generators, there are a number of concerns regarding system security and whether the future mix of generation would be appropriate to meet system requirements.

6.6 The Workgroup determined that Option D should not be progressed any further.

6.7 ***Consultation Question 12:*** Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.

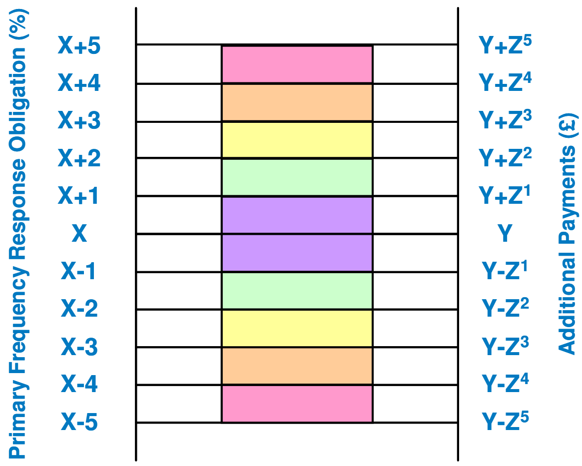
6.8 ***Consultation Question 13:*** Is there anything additional you wish to note regarding Option D?

7. Option E - Minimum capability obligation which is supported with incentives

7.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but rewards or penalises based on installed capacity. For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)
- Generator Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds
- Under Option E, Generator Y would receive additional income from providing primary frequency response above the minimum requirement whilst Generator X would be exposed to additional cost for not being able to meet the minimum requirement.

7.2 This income would be in addition to the income that generators already receive for providing frequency response (i.e. holding and energy payments). It is envisaged that generators who cannot meet the minimum obligation would pay a fee for each percent that they are short of the required minimum. Those generators that are able to provide frequency response above the minimum obligation would receive a payment for each percent above. Figure 7 below summarises the proposed incentives.



Where:
X = Minimum Obligation
Y = Existing Frequency Response Payment
Z = New Frequency Response Incentive

Figure 7 - Incentive structure

7.3 The Workgroup noted that this would penalise generation technology that finds it inherently difficult to provide frequency response for technical reasons but agreed that it is not expected that the costs for under provision would dissuade a generator from a particular choice of generation technology.

7.4 The Workgroup also believed that it could prove more economical for some generators to pay an additional cost for not being able to meet the minimum requirements rather than incurring the capital cost that would be required to allow the minimum obligations to be met.

7.5 The Workgroup have not developed this option any further than initial discussions but note that this option may have some merit worth investigating further.

7.6 ***Consultation Question 14:*** Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.

7.7 ***Consultation Question 15:*** Is there anything additional you wish to note regarding Option E?

8. Option F - System Operator provides response

8.1 This option proposes to reduce or remove the minimum Grid Code obligation on a generator to provide frequency response capability and instead have the System Operator procure the necessary frequency response volumes on a bilateral basis. For example:

- Generator X, a new generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (frequency response requirement removed)
- Generator Y, a new generator, has a Registered Capacity of 100MW and can provide 14% of primary response in 10 seconds
- Under Option F, National Grid would approach Generator X and Generator Y to discuss procurement of frequency response and agree terms on a bilateral basis. The amount of frequency response procured by National Grid would be based on plant outage, unavailability and system security. Both generators are compliant in this example as the obligation has been removed.

8.2 Payments would be generator specific and could be based on existing holding and response energy payment mechanisms. Alternatively, for new or life-extension generation, the payment could reflect an agreed amount of capital contribution to deliver the capability or a combination of the two. Payments for long term contracts could be index linked. Enhanced capability, either quantity or speed of response, would attract higher payment.

8.3 Contracts would be required for the service provision once a provider was appointed to ensure appropriate terms and conditions and to cover items such as term, payment and non-delivery. Plant would have to be tested to demonstrate it can achieve its capability profile. Compliance process would apply and National Grid could have option to re-negotiate price if capability no longer meets contracted position.

8.4 The Workgroup also discussed a scenario in which National Grid developed and owned frequency response equipment to meet system requirements. Whilst initially discussed it was considered unlikely to be an option going forward due to licensing restrictions and regulatory issues.

Impact on Operational Costs

8.5 Increased System Operator costs in terms of resourcing and running the procurement exercise.

8.6 The onus for the provision of frequency response would move from the generators to the System Operator and the Workgroup questioned if the System Operator is best placed to get the best provision. Arguably operational costs would increase if the System Operator is not best placed to get the best provision.

8.7 The System Operator would be exposed to fuel price risk if the capability procured through the tender process meant that the majority of frequency response came from units utilising a particular fuel source.

Impact on Generation Investment Costs

8.8 Lower investment costs could be seen for generators as not all generators would have to provide frequency response capability.

8.9 If providers were identified through a tender, this could show longer investment signals which could lead to more efficient and certain investment.

8.10 Price risk moved to System Operator with long term contracts which could be indexed linked by fuel but it would provide an incentive on generators to reduce operational costs to maximise margin.

Potential Cost Benefit

8.11 It is unclear if the increased System Operator costs to run a procurement process and any loss in efficiency with the System Operator not obtaining the best provision would be offset by potentially lower generator investment costs which could materialise in lower power prices.

8.12 Arguably the System Operator is not best placed to be making decisions that could expose them to fuel price risk and it adds additional complexity to the System Operator role which would likely materialise as increased operating costs.

Benefits of Option F

8.13 There are a number of benefits that can be identified:

- more options for providers to determine how and if they wish to provide frequency response;
- more options for National Grid to pick more economic and efficient frequency response solution;
- prevents consumer being exposed to cost of capability provided but unutilised frequency response cost;
- lower investment costs for generators;
- flexibility around contract duration and pricing structure; and
- actually procure based on the frequency response requirements.

Disadvantages of Option F

8.14 There are a number of disadvantages that can be identified:

- cost for development and implementation of appropriate IS systems;
- system security risk may not be maintained to current levels;
- increased complexity and additional process;
- increased System Operator costs;
- over procurement would be necessary to ensure enough frequency response available on the day;
- having one central buyer is arguably not the most efficient way to address the issue;
- not a very competitive solution or responsive to market signals; and
- long term contracts do not promote innovation and blocks new entrants.

8.15 The Workgroup agreed that whilst Option F had some benefits it did not seem that having a single procurer would encourage the most efficient solution. There was also concern that this option would not facilitate future innovation and could block new entrants from participating if long term contracts are agreed.

8.16 The Workgroup determined that Option F should not be progressed any further.

8.17 ***Consultation Question 16:*** Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.

8.18 ***Consultation Question 17:*** Is there anything additional you wish to note regarding Option F?

9. Option G - Day Ahead Auction

9.1 This option proposes to reduce or remove a minimum Grid Code obligation on a generator to provide frequency response capability and replace it with a day ahead auction.

9.2 To ensure that a mix of plant capable of securing the system is generating on any particular day, it is envisaged that at the day-ahead stage, the auction process would be initiated. The concept is similar to that of the Firm Frequency Response (FFR) tender but carried out on a daily basis rather than monthly. The Workgroup also recognised that a week ahead auction could be an alternative option if the timescales for a day-ahead auction proved too challenging or as an interim step between current arrangements and progressing to a day-ahead model.

9.3 To participate in the auction, which would be open to generation or demand-side providers, it would be necessary to be confident in the bidders' ability to deliver the agreed levels of response. Thus there may be a requirement for some pre-qualification process. It is likely the requirements for the Day Ahead Auction participants would be similar to that of FFR participants which are:

- have suitable operational metering;

- pass the FFR Pre-Qualification Assessment;
- deliver a minimum 10MW Response Energy;
- operate at their tendered level of demand/generation when instructed (in order to achieve the tendered frequency response capability);
- have the capability to operate (when instructed) in a Frequency Sensitive Mode for dynamic response or change their MW level via automatic relay for non-dynamic response;
- communicate via an Automatic Logging Device; and
- be able to instruct and receive via a single point of contact and control where a single FFR unit comprises of two or more sites located at the same premises.

9.4 For simplicity, it is expected at this time that the existing services of Primary, Secondary and High would remain although it is feasible that other products could be defined in the future. It is also assumed that the auction would be Balancing Mechanism Unit (BMU) specific, but a generic product could be developed.

9.5 Assuming that the frequency response auctions were to take place after submission of indicative Physical Notifications (PNs), a number of parameters would need to be submitted for assessment as part of the auction. The list below may not be exhaustive, but is a likely minimum requirement.

- MW of response offered - Primary, Secondary and High;
- required MW loading or de-loading to achieve the response offered;

  It is possible that this volume could be treated as equivalent to a bid or offer such that further energy trading would not be required, thus removing the price risk of not being able to cover a resulting physical position at the expected price.

- the positional price (£/h) for delivering the capability to the system;

  This would cover the cost of de-loading or loading to the appropriate level.

- an energy price for delivered energy resulting from frequency changes; and
- an initiation price.

  This would be particularly relevant for plant not expected to be running to cover start-up costs and would allow submission of bids for all periods during the day giving assurance that contiguous periods would be bought.

9.6 With the indicative PNs and submissions from potential response providers, whether expected to be running or not, the System Operator would assess the bids in order to determine the most efficient way of meeting the frequency response requirements for the following day.

9.7 Accepted bids would be expected to deliver as bid and non-delivery would need to be priced appropriately. It is likely that an appropriate monitoring process for delivery would be developed in parallel.

9.8 It is envisaged that within-day changes to the despatch decisions should be possible, and the BM would remain a mechanism to make such changes.

9.9 The Workgroup noted that Option G would not have to be based on the FFR framework but this was used as a starting point for discussion. Options could include:

- an FFR based mechanism with a mandatory obligation;
- an FFR based mechanism with a reduced obligation;
- an FFR based mechanism with no obligation;
- an alternative mechanism with a mandatory obligation;
- an alternative mechanism with a reduced obligation;
- an alternative mechanism with no obligation;

9.10 The Workgroup agreed that Option G merited further discussion and consideration.

Impact on Operational Costs

9.11 The Workgroup noted that with this option there would a potential systems impact to provide a day-ahead auction platform. It was recognised that the closer a process gets to real time the level of automation required increases and a day-ahead auction platform would require a large amount of automation which would likely have a large cost associated with it.

9.12 Along with the development of an appropriate platform there is the ongoing maintenance and resource cost that would be required. It was highlighted that this could have an impact on Electricity National Control Centre resources.

9.13 It was also noted that there would likely be interaction with other ancillary services and that operational systems would need to optimise the frequency response service with these other services.

9.14 If the system supported a single cost of response that could be submitted and if it takes away bid/offer analysis that is currently undertaken, it will provide better optimisation.

9.15 Prices could be more volatile at the day-ahead stage and could be higher compared to the week/month ahead.

9.16 It was highlighted that for demand side providers the certainty of their response capability increases closer to real time as demand becomes more certain.

Impact on Generation Investment Costs

9.17 The Workgroup suggested that the only reduction in generation investment costs would likely correspond with a reduction in obligation over time.

Potential Cost Benefit

9.18 A large capital expenditure would likely be required to establish a day-ahead auction platform and ongoing operational expenditure would be required to maintain and operate the system.

9.19 There are potential efficiencies in providing a day-ahead auction solution as it facilitates wider participation and enables all providers to be more certain of aspects such as fuel prices and system demand which could translate into lower operational costs for them. Providers would optimise their plant and provide response in the most efficient means possible.

9.20 There was concern expressed that if there is no obligation to provide response capability it could lead to higher BSUoS costs and put the system at greater risk.

Benefits of Option G

9.21 There are a number of benefits that can be identified:

- an auction for frequency response should ensure that the System Operator is able to procure a suitable mix of plant at the day-ahead stage such that sufficient frequency response is available for the anticipated requirement;
- all available plant should be able to participate as it would not be constrained by long NDZs etc which should result in greater price competition than within-day actions;
- plant scheduled to run would be able to provide best prices and therefore an efficient outcome should result giving the optimal mix of plant on the day;
- efficiency is gained by optimising both the energy and response decisions at the same time;
- encouraging other technologies and providing a platform for participation;
- could be a more gradual implementation compared to other commercial arrangements as it is similar to existing mechanisms;
- obligations could remain the same and if successful could be reduced over time;
- if the market size increases, existing sites may add on-site technology to increase their frequency response ability to participate;
- unlike the month ahead FFR market, the risk to providers with exposure to fuel / power price diminishes closer to real time.

Disadvantages of Option G

9.22 There are a number of disadvantages that can be identified:

- a day-ahead frequency response market would add a level of complexity and additional process;
- within day changes would still need to be managed by National Grid and plant failures would need to be managed through appropriate non-delivery charges and within-day despatch;
- likely to be expensive to develop and ongoing operational costs would depend on the type of system developed;
- providers may opt to participate in the energy market rather than the frequency response auctions which could put the system at unacceptable risk.

9.23 ***Consultation Question 18:*** Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.

9.24 ***Consultation Question 19:*** Is there anything additional you wish to note regarding Option G?

10. Option H - Minimum obligation for Supplier

10.1 This option proposes to introduce a minimum Grid Code obligation on a supplier to procure or provide frequency response capability based on the level of demand they are forecasting for a particular day. For example:

- Supplier A, has forecasted demand of 200MW for a particular day
- Generator X, has a Registered Capacity of 150MW and can provide 10% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)
- Generator Y, has a Registered Capacity of 150MW and can provide 10% of primary response in 10 seconds
- Under Option H, the supplier would contract with Generator X and Generator Y to provide the necessary frequency response based on their forecasted demand

10.2 The Workgroup identified that there seemed to be some benefit in placing the obligation on Suppliers to procure frequency response in proportion to the amount of generation they needed to meet their expected demand. This would allow the correct amount of frequency response to be available for any given level of demand, as well as helping Suppliers to understand the benefits associated with services such as frequency response.

10.3 The Workgroup also commented that demand is a useful and flexible way to respond to a frequency situation but in the past Suppliers have not been able to actively participate to frequency response due to technological limitations.

10.4 The Workgroup agreed that whilst there could be some benefits associated with this option it would be a complex solution that would require significant changes in requirements and utilisation of technology such as smart meters.

10.5 It was also recognised that if the supplier was expected to provide frequency response rather than procure it from other sources, it could be challenging to provide adequate frequency response in times of low demand.

10.6 Overall, the Workgroup did not view this as a viable option due the infrastructure (ie smart meters) required which is not available at this time but noted that, once the infrastructure is in place, it could be an option in the future.

10.7 ***Consultation Question 20:*** Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.

10.8 ***Consultation Question 21:*** Is there anything additional you wish to note regarding Option H?

11. European Network Codes

11.1 The Workgroup recognise the work that is ongoing on the European Network Codes (ENCs), specifically within the Network Code for Requirements for Grid Connection applicable to all Generators (RfG).

11.2 The development of the Network Code for Requirements for Grid Connection applicable to all Generators entered its formal phase after ENTSO-E received an invitation from the European Commission on 29 July 2011. The Commission officially requested ENTSO-E to draft this network code in line with Regulation (EC) 714/2009 and based on the Framework Guidelines on Electricity Grid Connection, published by ACER on 20 July 2011.

11.3 ENTSO-E launched a public consultation on the Network Code for Requirements for Grid Connection applicable to all Generators on 24 January 2012, which closed on 20 March 2012 ENTSO-E received over 6000 comments on the draft Network Code RfG.

11.4 On 13 July 2012, ENTSO submitted the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) to the Agency for the Cooperation of Energy Regulators (ACER).

11.5 At the time of writing, the final Network Code RfG, as well as its supporting documentation, is now subject to a three month evaluation period by ACER as prescribed in Regulation (EC) 714/2009.

11.6 Within GB, the current generator requirements are based on the following categories:

- Small (NGET <50MW, SPT <30MW, SHETL <10MW);
- Medium (NGET 50MW - 100MW, SPT N/A, SHETL N/A); and
- Large (NGET >100MW, SPT >30MW, SHETL >10MW).

11.7 Under the ENCs generator requirements are based on the following categories:

- A (800W - 1MW connected below 110kV);
- B (1MW - 10MW connected below 110kV);
- C (10MW - 30MW connected below 110kV); and
- D (>30MW or connected at 110kV or above).

11.8 Under the RfG, parameters for frequency response performance are specified by the Transmission System Operator (TSO) in accordance with Article 10 (2) (c) but in general these are similar to that required by the GB Grid Code. The TSO must define the parameters for minimum frequency response capability as a percentage of Registered Capacity (Pmax) which is between 1.5 – 10%, the Initial delay time shall be less than 2 seconds (which is not covered in the Grid Code) and full delivery of Active Power shall be achieved as specified by the TSO but shall be less than 30 seconds. Generating Units are to be capable of providing full Active Power frequency response (to be specified) for a period of between 15 minutes and 30 minutes and Generators must operate between their maximum and minimum headroom[7].

11.9 The above requirements only apply to categories C and D under RfG. The Workgroup were not aware of any elements of the ENCs that would prohibit the implementation of the any of the commercial arrangements discussed.

11.10 ***Consultation Question 22:*** Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?

11.11 ***Consultation Question 23:*** Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?

[7] See Article 10 (2) (c) - https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_RfG/120626_final_Network_Code_on_Requirements_for_Grid_Connection_applicable_to_all_Generators.pdf

1. Consultation Responses

1.1 If you wish to make a representation on this Workgroup Consultation, please use the response proforma which can be found under Frequency Response at the following link:

http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/

1.2 Responses are invited to the following questions:

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup?

- Requirement for Faster Frequency Response on asynchronous plant?
- Clearer Primary Response Requirements for synchronous plant?

***Consultation Question 2*:** Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

***Consultation Question 5*:** Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?

***Consultation Question 6*:** Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.

***Consultation Question 7*:** Is there anything additional you wish to note regarding Option A?

Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 9: Is there anything additional you wish to note regarding Option B?

Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 11: Is there anything additional you wish to note regarding Option C?

Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 13: Is there anything additional you wish to note regarding Option D?

Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 15: Is there anything additional you wish to note regarding Option E?

Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 17: Is there anything additional you wish to note regarding Option F?

Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 19: Is there anything additional you wish to note regarding Option G?

Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.

Consultation Question 21: Is there anything additional you wish to note regarding Option H?

Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?

Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?

1.3 Views are invited upon the proposals outlined in this consultation, which should be received by **30 October 2012**. Your formal responses may be emailed to:

Grid.Code@nationalgrid.com

1.4 If you wish to submit a confidential response please note the following:

- Information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response marked "Private and Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Grid Code Review Panel or the industry and may therefore not influence the debate to the same extent as a non confidential response.

- Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

2. Next Steps

2.1 Following the conclusion of the Workgroup Consultation, the responses received will be considered by the Workgroup and included in the Workgroup Report that will be submitted to the Grid Code Review Panel.

2.2 The Workgroup, while considering consultation responses, will determine which of commercial arrangements should be progressed to a more detailed assessment. The Workgroup will also consider industry views on the proposed technical requirements and conclusions of the Frequency Response Technical Subgroup.

2.3 The Workgroup would also like to invite interested parties to join the Frequency Response Workgroup to support further discussion and analysis. If you are interested in joining the Workgroup please contact:

Thomas Derry
Thomas.Derry@nationalgrid.com

Annex 1 - FR Workgroup Terms of Reference

Grid Code Frequency Response Working Group

Terms of Reference

It was agreed at May 2008 Grid Code Review Panel (GCRP) to establish a joint Grid Code and BSSG (Balancing Service Standing Group) Working Group. The Working Group would be tasked with reviewing the technical requirements and commercial mechanism applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

Objectives
The Working Group will:

i. examine the appropriateness of the existing Grid Code obligations and commercial mechanism for frequency response to the current and predicted future generation mix – including offshore generation;

ii. identify feasible options that will maintain the security of the National Electricity Transmission System following frequency deviations (inclusive of islanding scenarios), taking account of the characteristics of the current and next generation of power stations e.g. nuclear, supercritical coal, wind etc and the potential for demand management;

iii. identify and quantify the advantages and disadvantages of each option;

iv. identify all the impacts of each option on the Grid Code, CUSC and any other associated documents within the framework;

v. agree and recommend a preferred option;

vi. draft any text modifications necessary to implement the recommendation;

vii. monitor the progress of the National Electricity Transmission System SQSS review and take into account any impact on the frequency reserve holding requirement arising from its recommendations.

viii. consider frequency response provisions of any other comparable electricity networks worldwide

ix. Consider the interaction with the ongoing development of the European Network Codes.

Governance
The Working Group has been convened and will operate and be managed under the remit of the Grid Code governance framework.

Annex 1 provides an illustrative overview of the applicable amendments process for both the Grid Code and BSSG (which follows the CUSC governance framework).

Membership
The membership of the working group will be drawn from the GCRP or their nominated representatives, the BSSG and the Authority.

Deliverables
The Working Group will produce a report outlining its analysis, findings and recommendations which will be submitted to the GCRP, BSSG and CUSC Amendments Panel. A copy of the report should also be submitted to the Electricity Balancing System Group (EBSG).

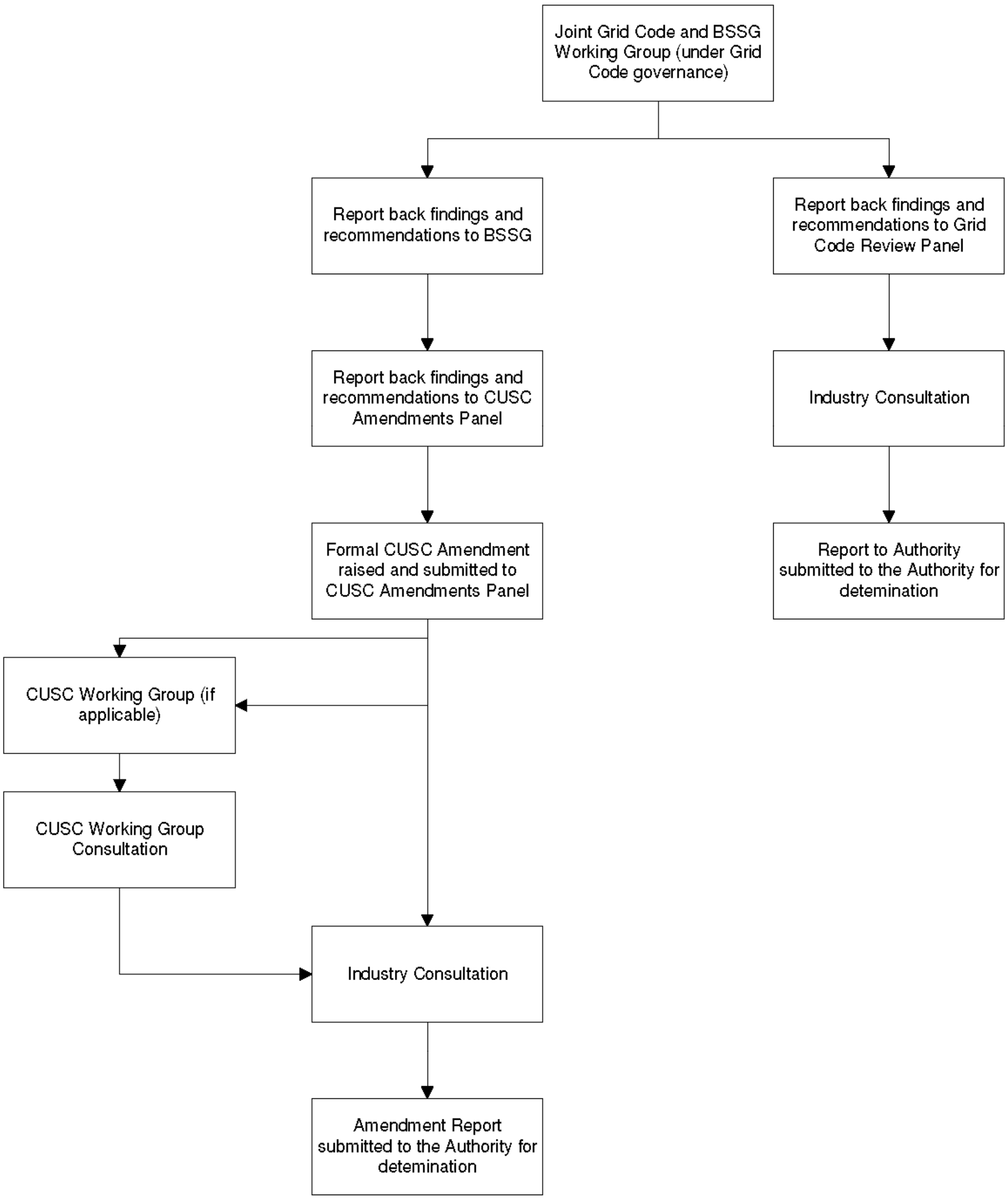
Timescales
The Working Group will present an Initial Conclusions Report to both the January 2012 GCRP and CUSC Panel meetings which will include:

- The findings and conclusions of the Technical Sub Group;
- A summary of the discussions and findings of the Working Group to date;
- Analysis of the options considered (technical and commercial) by the Working Group including those discounted;
- The Working Group preferred option(s) and relevant rationale.
- Detailed recommendations, which may include options, for the necessary further actions required to conclude the issue.

These Initial Conclusions will also be presented at the equivalent meeting of the BSSG.

Appropriate Final deliverables and associated timescales, will be agreed at the Jan 2012 GCRP meeting and Jan 2012 CUSC meeting.

Annex 1 – Working Group Governance Arrangements: Flow Chart



GCRP pp10/21
September 2010

Grid Code Review Panel Paper
Future Frequency Response Services

Paper by National Grid

1.0 Executive Summary

1.1 During the past 18 months, National Grid has been working with industry representatives as part of the Balancing Services Standing Group (BSSG) with a view to assessing the Frequency Response Services necessary to secure the System in the future[1].

1.2 By the year 2020, there are expected to be fundamental and profound changes to the Generation portfolio, which in turn, will have a substantial influence on the design and operation of the Transmission System. These changes include:-

- Substantial increases in Renewable Generation with some 29GW of wind alone (as per the National Grid Gone Green Scenario)
- Installed Wind Generation exceeding minimum demand of typically 25GW
- Substantial increases in non renewable generation including 3GW of new Nuclear, 3GW of Supercritical Coal and 11GW of new Gas.
- Larger single Generating Unit sizes of up to 1800MW

1.3 Many of these new generation technologies have very different characteristics from the current generating fleet. There are therefore a number of key issues which need to be addressed on an urgent basis to ensure the maintenance of Transmission Security, particularly with regard to the control of System Frequency. These issues include:-

- Variable speed wind turbines which will form the majority of the wind generating fleet do not currently contribute to system inertia. The impact of which is a substantial increase in the rate of change of system frequency and the potential for a lower minimum system frequency following loss of generation.
- With the largest Generating Unit loss potentially increasing to 1800MW this issue will become worse.
- The rate of Change of System frequency will increase which will have implications for the protection settings of Embedded Generation.

1.4 The combination of these changes mean that it is essential that an assessment is undertaken of the technical system need for response services. This assessment should include:-

- A fundamental review of the minimum requirements for primary response.
- The need for modern variable speed wind turbines and similar plant to contribute towards system inertia.
- A review of the Rate of Change of Frequency Protection Settings for Embedded Generation

1.5 These issues are highly interrelated and cannot be considered in isolation. National Grid has been working to develop a synthetic inertia requirement and these high level proposals are detailed in this paper. However these proposals need to be considered alongside the issues highlighted above and National Grid recommends that a Grid Code Working Group is established to determine the technical system need for frequency response services going forward. This working group needs to progress in a timely manner such that any revised technical requirements are incorporated into the build programme of the anticipated new generation fleet.

[1] This paper will be discussed by the BSSG on 10 September 2010 in which any additional developments will be raised verbally at the Grid Code Review Panel meeting on 23 September Grid Code Review Panel Meeting.

2.0 Introduction

2.1 This report is intended to give the GCRP an appreciation of the technical issues raised at the Balancing Services Steering Group (BSSG), an overview of the work completed to date and the future issues that need to be resolved going forward.

2.2 Due to global pressures over the last decade, the electricity supply industry has been turning increasingly to renewable sources of generation. Environmental concerns about fossil fuelled conventional generation, security of fuel supply and the increasing cost of fossil fuel are leading to greater calls for renewable generation.

2.3 National Grid has witnessed these changes over the last few years, through its own research, but more importantly through the volume and scale of the connection applications. To this end, National Grid has published its best estimate of the Transmission System in 2020 under a Gone Green Scenario. The key elements of this can be summarised as follows:-

- Plant Closures
  - 12 GW Coal & Oil – Low Combustion Plant Directive (LCPD)
  - 7.5 GW of Nuclear
  - Some Gas and Coal

- Significant New Renewable
  - 29 GW wind (2/3 Offshore)
  - Some Tidal, Wave and Biomass
  - Renewable share of generation grows from 5% to 36%

- Significant new non renewable build
  - 3GW of new nuclear
  - 3GW of Supercritical Coal (some with Carbon Capture)
  - 11GW of new gas

- Electricity demand remains flat (approx 60GW peak)
  - Reductions from energy efficiency measures
  - Increases from heat pumps & cars

2.4 Many of these new generation technologies have very different characteristics from the current generating fleet. There are therefore a number of key issues which need to be addressed on an urgent basis to ensure the maintenance of Transmission Security, particularly with regard to the control of System Frequency.

2.5 Of these generation technologies, variable speed wind turbines which could, under a National Grid Gone Green Scenario, at times exceed the minimum demand, do not currently contribute to system inertia. The impact of which being a substantial rise in the rate of change of system frequency and the potential for a lower minimum frequency following loss of Generation.

2.6 At the present time, the maximum loss permitted under the SQSS is 1320MW. National Grid as System Operator is responsible for the Control of system frequency, with minimum stipulated limits of 49.2Hz, recovering between 49.5 Hz and 50.5Hz within 60 seconds of the disturbance.

3.0 Synthetic Inertia

3.1 The issue of inertia and its importance from a Power System perspective are detailed in Appendix A. In summary, a conventional synchronous generator will supply a small injection of additional active power to the network following the loss of another generator. This natural phenomena greatly assists in limiting the rate of change of system frequency and hence the minimum frequency reached. Unfortunately, modern variable speed wind turbines and generators decoupled from the power system (for example those which utilise power electronic converters) are insensitive to frequency changes and therefore do not provide the same facility as their synchronous counterparts. The effect of which is left unchecked in the diminution in system frequency. This issue is clearly demonstrated in Figure 1 below where the system inertia is reduced by half.

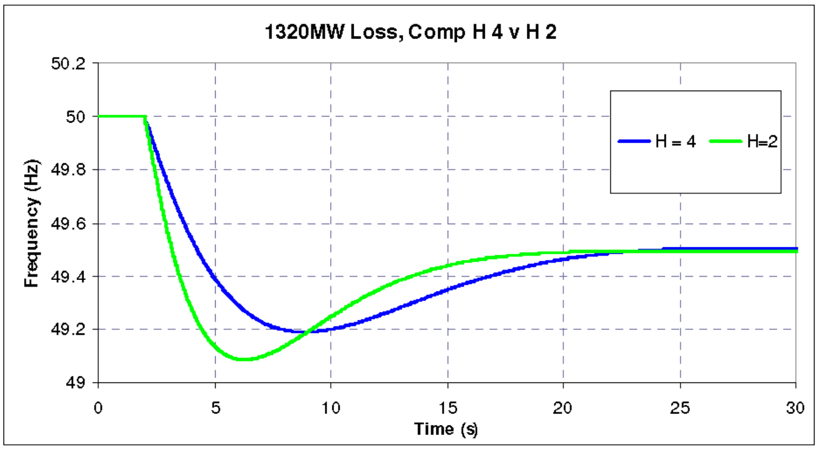


Figure 1.0

3.2 National Grid has completed its own research and there is clear evidence to demonstrate the ability of a wind turbine to provide an inertial response capability. The details of this capability is discussed in detail in Appendix A together with high level proposals.

3.3 Although further dialogue is required with the manufacturers in relation to these high level, but as yet uncompleted proposals, there is ongoing discussion with regard to the recovery period. This issue is described in more detail in Appendix A, but in summary, once the wind turbine has released additional energy to the system it will need to recover if it has been operating below rated wind speed. The consequences of which are a temporary drop in power production which is most severe just prior to operation at rated wind speed. This issue has serious consequences for National Grid in controlling system frequency as shown in Figure 6.0A of Appendix A. However National Grid is working closely with manufacturers to see how this issue can be addressed.

3.4 For the avoidance of doubt none of the measures relating to the provision of a synthetic inertia capability require any pre fault curtailment. In addition if the wind turbine operates at or above rated wind speed no recovery period is necessary.

4.0 Synthetic Inertia under an 1320 MW Loss Scenario

4.1 If the issue of wind generation is considered in isolation, and the assumption that the largest system loss remains unchanged at 1320MW, then it is believed that security standards and frequency control could be managed by introducing a requirement on wind generation and similar plant to contribute towards system inertia. Based on the studies to date, it is also believed that retaining a 1320 MW loss would not lead to a requirement to change other Grid Code obligations such as the minimum requirements for the delivery of frequency response. Appendix A of this report provides further background on the issue of inertia and the proposals that National Grid has developed in progressing this issue.

5.0 Primary Response and Synthetic Inertia under an 1800MW Loss Scenario

5.1 With the introduction of a new generation of nuclear power stations, consideration is being given to increasing the largest loss from 1320MW to 1800MW. The consequent impact of this change is higher rates of change of system frequency and lower potential minimum frequencies which could fall outside the statutory minimum frequency range.

5.2 As part of the work by National Grid to develop a synthetic inertia requirement, it was established that even under a system operating condition at a minimum demand of 25GW, with an 1800MW loss and the system comprising solely of synchronous plant (ie a light wind condition) and relying on the minimum primary response conditions of the Grid Code (ie 10% in 10 seconds) the system could not be secured. Although some of the analysis edges on the pessimistic side, and did not include contracted demand tripping, or faster governor action, the conclusion drawn is that whilst primary response volumes will have to increase slightly from current levels in proportion to the largest loss, the speed of delivery needs to be far faster (in one example full delivery being required in 5.5seconds from the event).

5.3 On the other hand, for a high wind condition (ie 1 synchronous generator of 1800MW which is subsequently tripped, some conventional plant providing 1500MW of primary response and the reminder being wind) the action of synthetic inertia can be made to secure the system. The issue however is that wind generation would be providing a far higher equivalent inertial contribution than its synchronous counterparts and this raises the question whether the calculated volumes of synthetic inertia are necessary if the Grid Code requirements for the delivery of primary response was faster than current levels.

5.4 The key conclusion from this work is there is an inherent link between the volumes and more importantly the delivery of the primary response required against the requirement for the volume of synthetic inertia. Thus, until the minimum requirements in terms of volume and delivery of primary response have been defined for an 1800MW loss, using synchronous generation only, it is not possible to finalise the inertia requirements for wind generation. The final element of this work would then be to review the rate of change of frequency protection settings for Embedded Generation.

6 Conclusions

6.1 Based on the expected growth of future renewable generation there will be a requirement for a synthetic inertia capability to be fitted to all generation and DC Converter technology which does not have a natural capability to contribute to system inertia.

6.2 Such a requirement would need to be introduced in the very near future ahead of the build program for the latter Round 2 and Round 3 projects but also the larger onshore wind farms.

6.3 National Grid is actively working with manufacturers to assess their views on these proposals. National Grid is also working with manufacturers to understand and limit the effect of the recovery period.

6.4 There is a close interaction between the settings of an inertial response requirement and the volume / speed of delivery of primary response. It is possible to develop settings for a 1320MW loss, however whilst settings for an 1800MW loss can be engineered they cannot be finalised until the issue of Grid Code requirements for Primary Response under an 1800MW scenario have been finalised.

6.5 Based solely on the current Grid Code requirement of 10% primary response to be delivered in 10 seconds, this requirement alone is insufficient to secure the system for an 1800MW loss unless other measures such as faster governor action or load tripping is considered. This issue was identified in the SQSS Review Report GSR007.

6.6 The implications on rate of change of frequency need to be assessed and the issues explained to the Distribution Code Review Panel for assessment in terms of embedded generation protection settings.

6.7 In view if these issues, it is noted that whilst a substantial amount of work has been completed, there are a number of outstanding issues and interactions which require resolution, before final proposals can be submitted for consultation.

7 Recommendations

7.1 National Grid recommends that that a Grid Code Working Group is established to determine the technical system need for frequency response services going forward. This working group needs to progress in a timely manner such that any revised technical requirements are incorporated into the build programme of the anticipated new generation fleet.

7.2 Continue to develop and work with manufacturers on the development of an synthetic inertia requirement against the context of the working group recommended in section 7.1 above and understand the impact of the recovery period in more detail.

7.3 Advise the Distribution Code Review Panel of the issues to Rate of Change of Frequency and the implications for Embedded Generation.

APPENDIX A

1.0 Background to Wind Generation

1.1 The most widely available and fastest growing technology that is being used to meet Renewable Generation Targets is wind turbines: the main types of which being the Doubly Fed Induction Generator (DFIG) and Full Converter Generator. The National Electricity Transmission system currently has an installed wind turbine capacity of 4.5GW. The current expectation under the National Grid Gone Green scenario is 29GW of wind, with a further 10GW by 2030.

1.2 However, the level of penetration as outlined above will not be realised without the industry overcoming a number of issues which arise due to the changing power system environment. One of the technical issues that these technologies present is that they decouple the generator from the power system as can be seen in Figure 1.0A and hence reduce the total system inertia compared to that of a Power System consisting wholly of conventional synchronous generators. It is therefore important to consider their growing effect on the frequency stability of the National Electricity Transmission System.

DFIG and Full Converter turbine arrangements

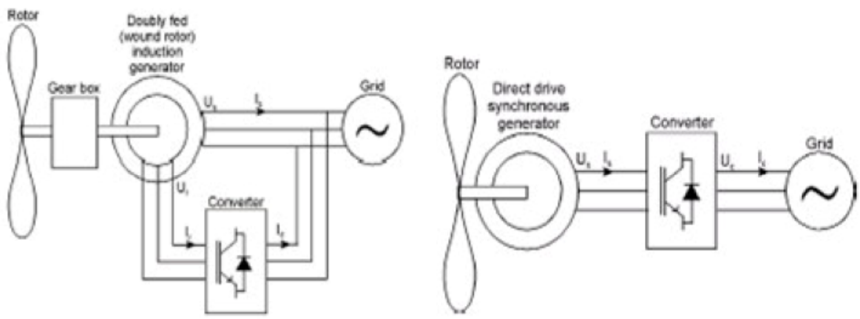


Figure 1.0A

Source:- Han Slootweg - Delft University of Technology - Presented in Dublin 6 March 2003

2.0 The Effect of Inertia

2.1 The inertial response of a Synchronous Generator, is the initial power injection to the Transmission System following a change in system frequency caused by a disturbance such as a loss of generation or sudden increase in demand. The inertial response is governed by the following equation.

$$H = \frac{\frac{1}{2} J\omega^2}{MVA} \quad \text{- (1)}$$

Where:- H = Inertia constant in MWs / MVA
J = Moment of inertia in kgm^2
ω = nominal speed of rotation in rad/s
MVA = MVA rating of the machine

2.2 The Inertia Constant is defined as the stored energy in the rotating mass at the rated speed in MWs/MVA. The majority of generators connected to the National Grid Transmission System have an inertia constant H of between 3MWs/MVA and 9MWs/MVA. The inertial response can only be delivered by generation where there is no decoupling between the Generator and Transmission System. This rotating mass is made up of the turbine and the generator shaft.

2.3 Following a System disturbance which results in an imbalance between supply and demand, the inertia prevents an instantaneous change in speed. The rate of change of the speed will be governed by the following equation:

$$df/_{dt} = \frac{\Delta P}{2H} \quad - (2)$$

Where: df/dt = rate of change of frequency
ΔP = MW of load or generator loss
H = H is the System Inertia Constant in MWs/MVA

2.4 System inertia is vital in limiting the rate of fall of frequency following such an event. The lower the inertia, the faster the rate of change of system frequency. This effect can be seen in Figure 2.0A below, where reducing the system inertia from 4 down to 2 results in a faster rate of change of frequency and a lower minimum frequency. In this example, the same volume and speed of primary response was used. The key point, being that the steady state frequency post event is the same in both cases.

Comparisons of different system Inertias

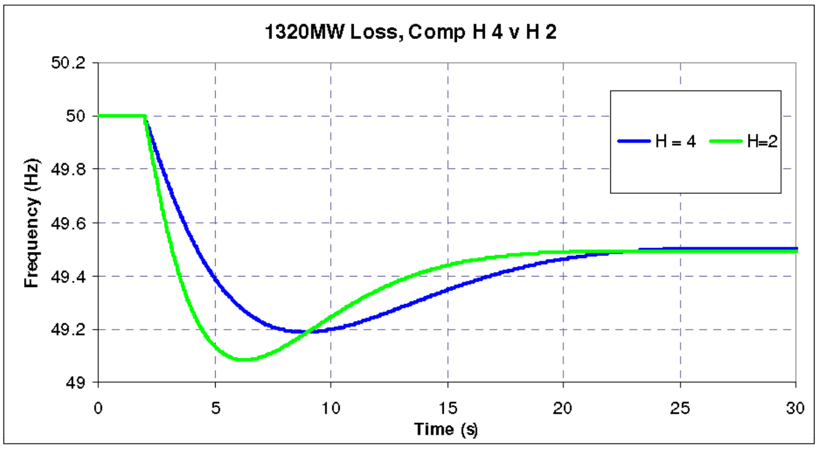


Figure 2.0A

2.5 Consequently, any diminution in inertial response will be significant during a frequency event. It will have a material effect on the ability of the system to contain the maximum frequency excursion and recover from large system frequency disturbances. As can be seen from Figure 2.0A, the greater the inertial response, the more time that will be given to other elements of the power system to regulate their output to help arrest the frequency fall. Consequently there is a close correlation between the inertial response, the speed of delivery of primary response and the rate of change of frequency (ROCOF) which has implications for some embedded forms of power system protection.

2.6 Figure 3.0A demonstrates the stages which occur in controlling frequency on a power system following a generation loss. The black trace would be the expected frequency trace for a large instantaneous loss of generation on the power system. The red trace shows the short term injected active power to the system as a result of the inertia of the drive train. This additional injection of active power to the network results from the inertial contribution in which the stored energy in the drive train is effectively the areas under the red curve. Governor action will take place shortly after the frequency deviation typically within a 1 – 1.5 seconds although the Grid Code permits a maximum delay of 2 seconds with full delivery within 10 seconds of the event and sustained for a further 20 seconds. Secondary response will then become active being delivered within 30 seconds of the event and sustainable for a further 30 minutes. The frequency does not return to nominal but to a value slightly less than this. It will be tertiary action by the National Grid control room that will return it to the nominal value

Elements of Frequency Control on a power system

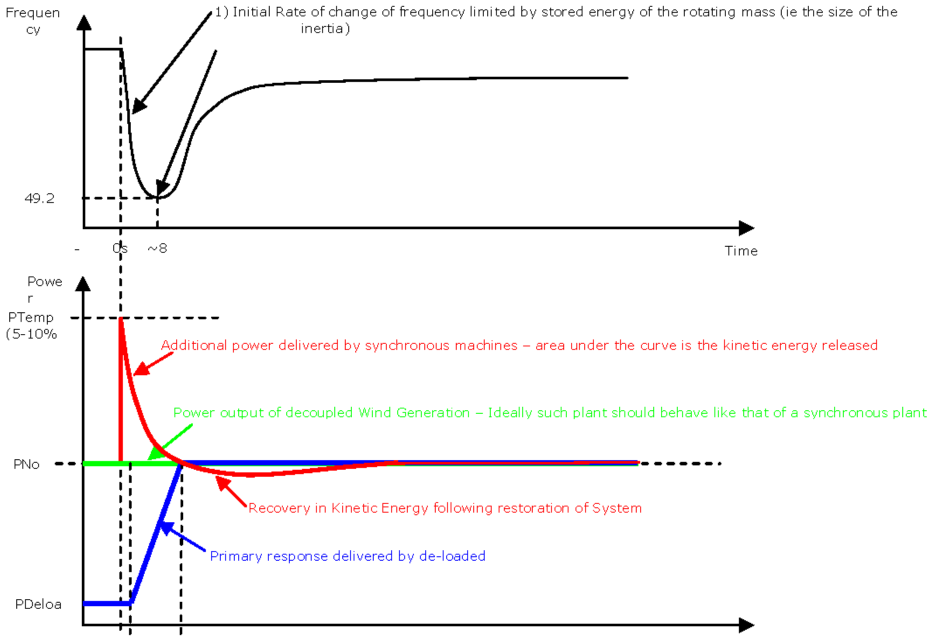


Figure 3.0A

2.7 The concern for power system operators is the green line which shows the output of decoupled plant such as variable speed wind turbines (assuming constant wind speed) which are insensitive to system frequency changes which would have the effect of exacerbating a frequency incident. As the new types of asynchronous wind turbines do not contribute to system inertia it will be vital for system operators to look at specifying a technical requirement for synthetic inertia from wind turbines.

3.0 Synthetic Inertia

3.1 It is clear that with the large volume of renewable generation and HVDC links envisaged in 2020 and beyond, it will become increasingly difficult to secure the system for a maximum loss. If the inertia issue were left unresolved, then it would become increasingly difficult to secure the system, to the extent that significant constraints would need to be imposed at significant operational cost as highlighted in the SQSS GSR007 report.

3.2 As an alternative lower cost solution, consideration has therefore been given to requiring Generating Units, Power Park Modules and DC Converters which are insensitive to frequency changes to have the capability to deliver a power injection to the System following the loss of another Generating Unit, in a similar way to that of a synchronous machine.

3.3 The ability of wind turbines to provide an inertial capability is well documented and a number of papers [1], [2], [3], [4] support this capability, even to the point of full scale tests. The advantage is that such a capability can be achieved without pre fault curtailment although there is some concern with regard to the recovery period when a wind turbine is operating just below rated wind speed. This issue is discussed in more detail below.

3.4 In addition to this capability, Hydro-Quebec of Canada specify a minimum requirement for inertia in their Grid Code [5]. Additionally, the need for synthetic inertia requirements are being introduced through the ENTSO-E working group which is tasked with harmonising Grid Code connection requirements across Europe.

4.0 Background to high level Synthetic Inertia Proposals

4.1 The high level, but as yet, incomplete proposals for synthetic inertia (as mentioned in the Appendix of the main report) are detailed in Appendix B. In summary, the requirement would be based on that which would be delivered from a synchronous machine, but initiated through control system action.

4.2 The Controller would operate so as to inject active power to the network in proportion to the rate of change of system frequency. For a small loss, say 300MW, only a small df/dt would result thereby driving a small initial injection in active power, with the subsequent decay again being proportional to the rate of change of system frequency. This would drop off with time as the action of primary response acts to reduce the frequency fall.

4.3 Likewise, for a larger generation loss, say 1320MW, the same principle would apply, the only difference being that df/dt would be much higher, so the initial injection of active power to the system would be much higher.

4.4 In developing the high level proposals for synthetic inertia, National Grid has used two analysis tools in addition to real system data from its Network Operations centre at Wokingham. The analysis tools include a detailed spread sheet and a full dynamic model in Digsilent power factory which includes detailed governor models. The results of both analysis tools have been compared and verified with consistent results being achieved and compared against real incidents recorded at the National Electricity Control Centre.

5.0 Wind Turbine Inertial Capability and Recovery Period

5.1 The method in which a wind turbine can produce an inertial response capability is well documented in [2], in which Figure 3 of this referenced paper (replicated below as Figure 4.0A) shows the method in which the wind turbine is capable of producing an inertial response without prefault curtailment.

5.2 There are however, serious concerns with regard to the reduction in active power following such periods of overproduction, particularly at a range of wind speeds just before operation at rated wind speed. In some cases, in the critical wind speed range, the power output can drop as low as 75% of the pre fault power output, even if the wind speed remains unchanged. For the avoidance of doubt, the recovery period is not required at wind speeds at or above rated wind speed and the recovery period at low wind speeds is believed to be manageable.

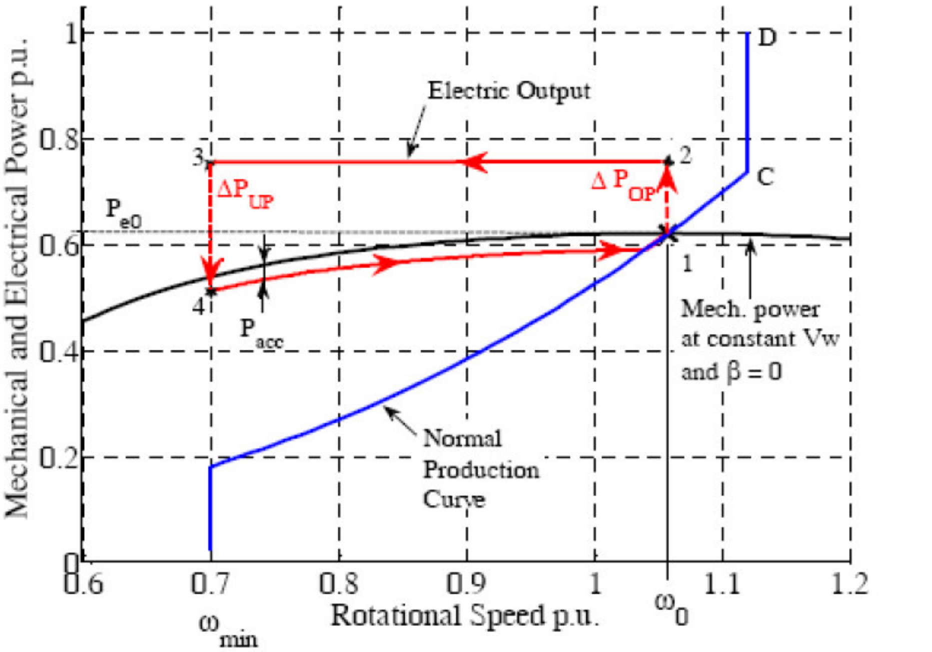


Fig. 3. WT power vs. rotational speed. The blue line is the WT normal (static) production power. The black line is the blade's mechanical power for a constant wind speed. The red line is the electric power set point for over-production process.

Figure 4.0A

5.3 National Grid has used this information to understand the impact of the recovery period on the Transmission System. Under worst case conditions, the system frequency will experience a double dip as shown in Figure 6.0A below. Figure 5.0A shows the critical operating point on the Wind Speed / Power Curve and Figure 6.0A shows the effect on system frequency as a result of the drop in active power during the recovery period, which as can be seen has serious system consequences.

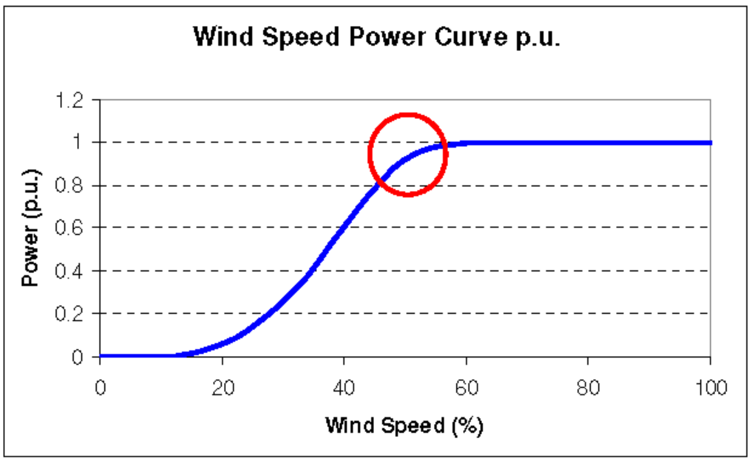


Figure 5.0A – Critical Wind Speed Recovery Period

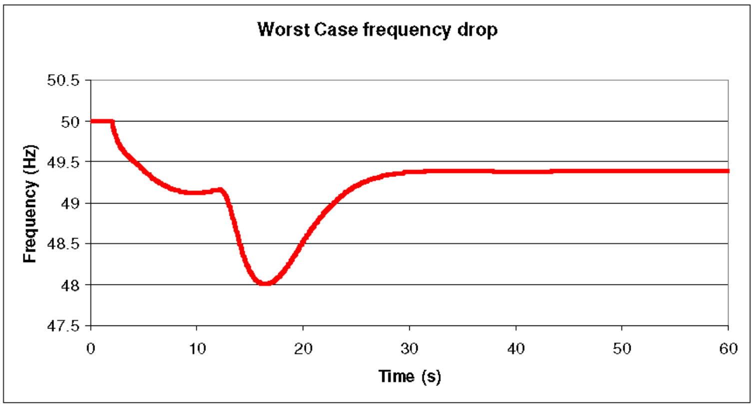


Figure 6.0A – Effect on System Frequency as a result of the Recovery Period at Critical Wind Speeds

5.4 National Grid is actively working with all manufactures to see what mitigation measures can be applied to minimise the effect of the recovery period. Based on the research to date, the recovery period is influenced by the variation of wind speed within the wind farm, the volume of inertial response required (ie 10% decaying exponentially over a 10 second period will have a higher recovery period than say 5% over a 5 second period). Clearly this requirement is inherently linked to the volume and speed of delivery of primary response, which would be exacerbated under an 1800MW loss scenario. The effect of the recovery period can also be minimised by some pre fault curtailment but this would not be considered as a favoured option based on the loss of revenue to Generators, but also the wider system operating costs.

6.0 Rate of Change of System Frequency (ROCOF)

6.1 As has been described, the introduction of large volumes of renewable generation to the Transmission System which do not contribute to system inertia has the effect of increasing the Rate of Change of System Frequency (ROCOF). Although the introduction of a synthetic inertia requirement is being proposed, this would be based on a control action using df/dt with the full injection of active power being required within 200ms of the generation loss. The consequences of which are a substantial increase in the rate of change of system frequency over the first few 100's of milliseconds until the inertial response has had an opportunity to take effect. Based on system studies, the Rate of change of system frequency in a purely wind based scenario doubles from current levels. By way of example, for an 1800MW loss and a full wind scenario rates of change of frequencies in excess of 0.5Hz/s where observed.

6.2 There are implications for this effect. Embedded Generators connecting to a Network Operators System are required to satisfy the requirements of ER G59 or ER G75 as appropriate with further guidance being referenced in Engineering Technical Report ETR 113. For Embedded Connections, Rate of Change of Frequency Relays are often specified as a form of islanding protection with the settings specified in the Engineering Recommendations referred to as above.

6.3 In view of the substantial increase in rate of change of frequency as a result of the changing generation mix, further consideration will need to be given to the recommended protection settings in the Engineering Recommendations and such an issue will need to be discussed by the Distribution Code Panel Review Panel.

7.0 Noise Injection

7.1 The requirements for a synthetic inertia controller rely on a df/dt function. Derivative Controllers by their very nature have the tendency to amplify noise and therefore such proposals include a requirement for adequate filtering so as not to cause undue consequences for other Users of the Transmission System.

8.0 References

[1] Contribution of Wind Energy Converters with Inertia Emulation to frequency control and frequency stability in Power Systems – Stephan Wachtel and Alfred Beekmann – Enercon – Presented at the 8th International Workshop on Large Scale Integration of Wind Power into Power Systems as well as on Offshore Wind Farms, Bremen Germany, 14 – 15 October 2009.

[2] Variable Speed Wind Turbines Capability for Temporary Over-Production – German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

[3] Study on Variable Speed Wind Turbine Capability for Frequency Response - German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

[4] GE Energy – WindINERTIATM Control fact sheet – Available on GE Website at :- http://www.ge-energy.com/businesses/ge_wind_energy/en/downloads/GEA17210.pdf

[5] Transmission Provider Technical Requirements for the Connection of Power Plants to the Hydro-Quebec Transmission System – February 2006

APPENDIX B

1.0 High Level Initial Grid Code Proposals

1.1 In order to limit the rate of change of frequency following a generation loss, each Generating Unit, Power Park Module (including Power Park Units thereof) or DC Converters which are insensitive to changes in system frequency and do not inherently contribute to system inertia shall be required to supply (via control action) additional Active Power to the System in the form shown below in Figure 1.0B.

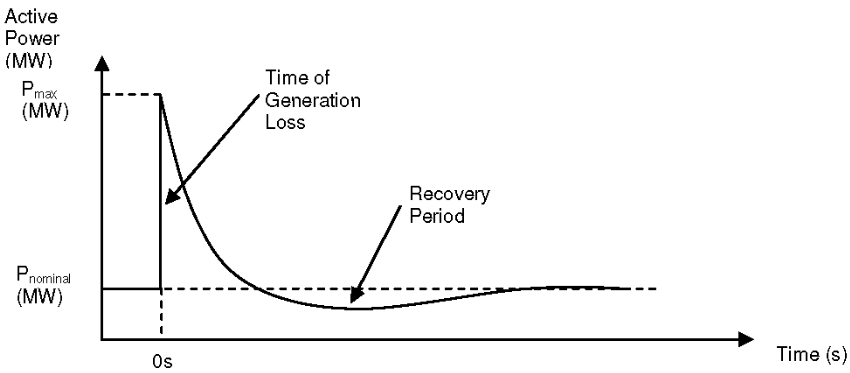


Figure 1.0B

1.2 For a rate of change of frequency of *TBA* or greater, the maximum injected power supplied to the System shall be required to be TBA of the Rated MW output of the Generating Unit, Power Park Module or DC Converter.

1.3 The Active Power delivered to the System should be fully available within 200ms.

1.4 Following the initial increase in Active Power supplied to the System, Active Power should reduce exponentially in proportion to the rate of change of system frequency.

1.5 In order to reduce excessive frequencies for small generation losses, the initial Injected power supplied to the Transmission System shall be in proportion to the rate of Change of System Frequency as shown in Figure 2.0B with an example being shown in Attachment B1.

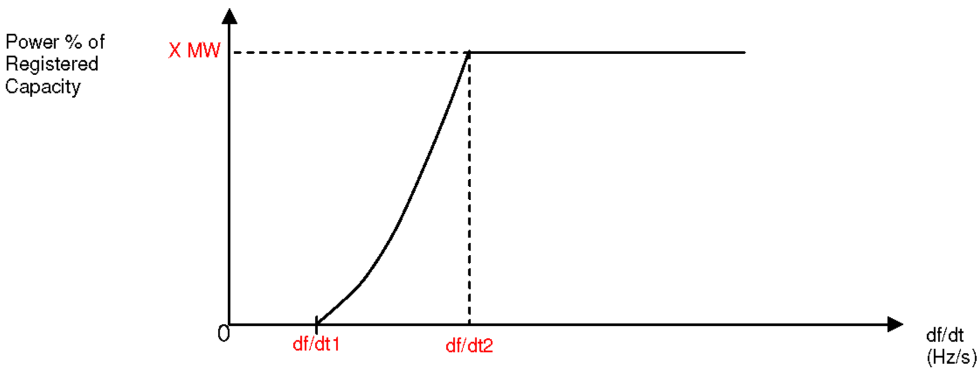


Figure 2.0B

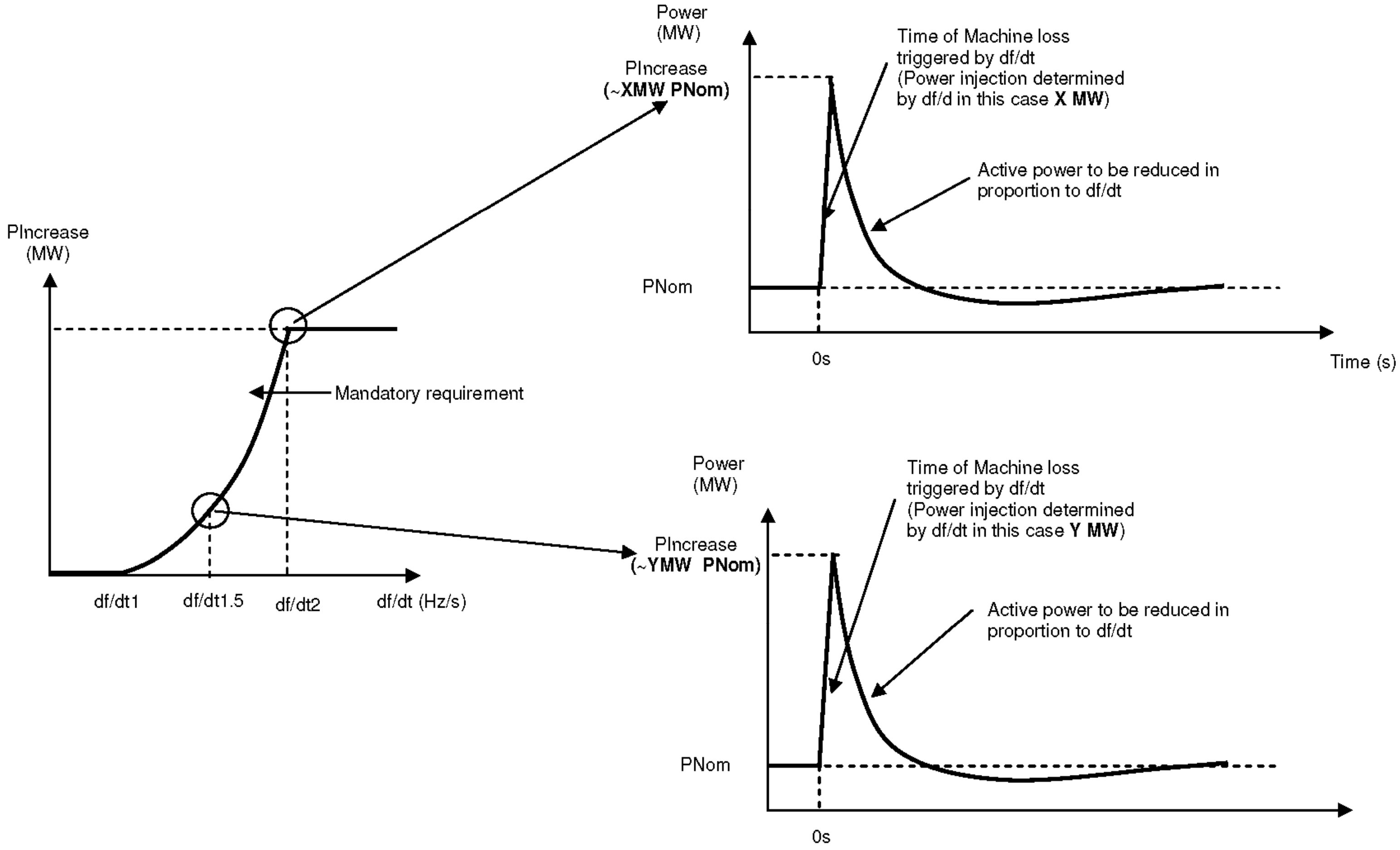
1.6 Following injection of the Active Power to the Transmission System and the subsequent exponential decay, with the Generating Unit, Power Park Module or DC Converter running at rated output only, a small recovery period shall be permitted *(This is still to be confirmed but would be limited to typically a peak of 3 - 5% of Rated MW output recovering over a 60 second period)*.

1.7 This recovery period shall be limited so as to prevent excessive deviations in System Frequency after the initial injection in Active Power has been delivered.

1.8 In addition, the Control System fitted to each Generating Unit, Power Park Module and DC Converter shall:-

- have an adjustable dead band of between 0.02 Hz/s – 0.5Hz /s in step sizes of 0.01Hz/s. The initial dead band shall be set to TBA
- Include elements to limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the Generating Unit, Power Park Module (including the Power Park Unit thereof) and DC Converter should also meet this requirement.

ATTACHMENT B1



Annex 3 - FR Technical Subgroup Terms of Reference

Grid Code Frequency Response Technical Sub Group

Terms of Reference – dated November 2010

It was agreed at the 14th Frequency Response Working Group meeting to establish a Technical Sub Group. The Technical Sub Group would be tasked with assessing the volume of Frequency Response and inertial requirement for the transmission network.

Objectives

The Technical Sub Group will:

(i) determine the total volume of Transmission System Frequency Response and Synthetic Inertial requirements;

(ii) consider a largest secured loss of both 1320MW and 1800MW for the scenarios described in i) above; and

(iii) work on the initial assumption is that obligations are mandatory and equal.

Membership

Membership will be invited from relevant manufacturers, National Grid, Generators and a representative will be requested from the DCRP

Deliverables and timescales

Three meetings are anticipated. The Technical Sub Group will produce a technical report outlining its analysis, findings and recommendations which will be submitted to the Frequency Response Working Group by the end of February 2011. This will allow the Frequency Response Working Group to report to the September 2011 meeting.

1. Background

1.1 A major element of this study work is to establish the effect on System Frequency of the increasing volume of variable speed wind turbines and HVDC Converter technology. Whilst these issues are now well known, and set out in the 'Future Frequency Response Requirements' paper (Annex 3), it is worth briefly summarising the potential concerns.

1.2 Conventional synchronous generation which currently contributes to the majority of the Transmission System load is sensitive to changes in system frequency. In the event of the loss of a generating unit, the remaining synchronous plant will supply an injection of active power into the network through the stored energy in the rotating masses. This natural phenomena greatly assists in limiting the rate of change of system frequency.

1.3 Unfortunately, variable speed wind turbines and other static devices which utilise power electronic converters such as HVDC converters are insensitive to frequency changes and therefore do not behave in the same way as synchronous machines resulting in a diminution in the system frequency. This issue is illustrated in Figure 1 below.

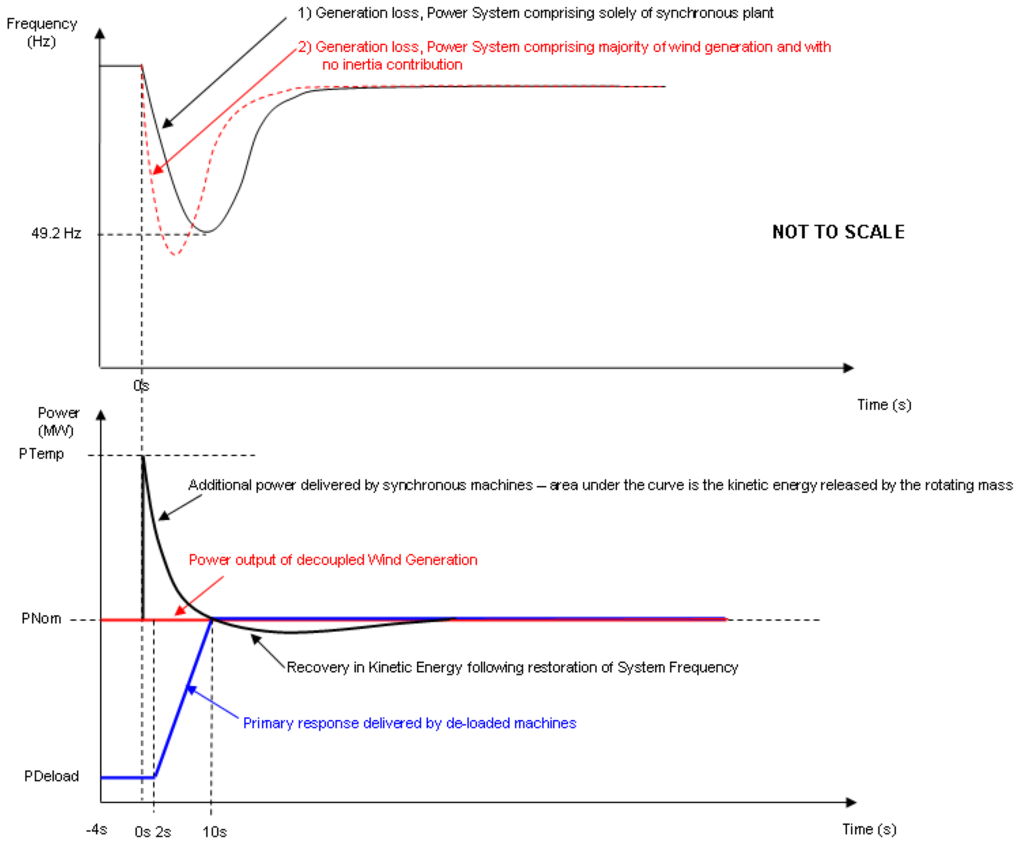


Figure 4: The effect of reduced system inertia on the management of a large infeed loss

1.4 As can be seen in the red curve of Figure 1, for the same generation loss, it is not possible to maintain the System Frequency above 49.2Hz when a high volume of asynchronous generation is connected to the system and unable to contribute to system inertia. The reason for this is the lack of Active Power (shown by the red line) injected from the asynchronous generation as shown in the lower graph.

2. Initial Discussion

2.1 The Workgroup discussions focussed on two approaches to managing large frequency deviations on systems where a lack of 'natural' inertia meant that the system frequency may not be contained within satisfactorily limits.

2.2 The first approach considered was to investigate the option of equipping variable speed wind turbines and other asynchronous sources with a 'synthetic inertia' capability. This capability has the potential to improve frequency control without needing to curtail the power output of the wind turbine generating units prefault. This option was investigated at length and detailed discussions where held with a number of the major wind turbine manufacturers.

2.3 A number of manufacturers have indicated an ability to provide a synthetic inertia capability and have published papers and information on their capabilities - see references [1] – [4] in Annex 5. These controllers aim to inject power to the network in a similar way to that of a synchronous machine, but through controlled action.

2.4 As part of a control strategy, it is important to ensure sufficient active power is injected into the network to balance the loss of generation. Clearly too much active power injected into the network could result in temporary over frequencies occurring before governor action provides adequate downward regulation. For example, with a loss of generation of less than 300MW, only a small amount of active power would be required where as a larger injection would be required for the maximum loss of 1,800MW.

2.5 A good measure of the required level of active power injection can be obtained from a measure of the rate of change of system frequency (df/dt) (ie the smaller the value of df/dt the lower the initial injection of active power required).

2.6 National Grid modelled two controllers both using df/dt functionality. One was based on an initial injection and fixed decay based on the rate of change of system frequency. The second was based on a continuously acting df/dt controller which would operate throughout the entire disturbance, and in doing so regulating the active power injection to the network continuously. Based on the results, both controllers were able to inject sufficient active power to the network to ensure the maintenance of system frequency above SQSS limits. These are described in more detail in Annex 5.

2.7 Whilst system studies confirmed that both controllers could be used as a basis to resolve the issue of retaining frequency standards, further discussion identified two critical issues. These being:

- df/dt controllers are noise amplifying and can, even with appropriate filtering, fail to operate in the appropriate manner, particularly where small time constants are involved; and

- the recovery period for wind turbines operating at just below rated wind speed can result in substantial reductions in their active power output, resulting in a system frequency collapse some 10 to 15 seconds after the initial generation loss.

2.8 With regard to the df/dt issue, National Grid held extensive discussions with manufactures to examine the df/dt controller and how it could be improved. National Grid amended their own models and identified that even with slower response times the controller could still aid frequency containment.

2.9 It was also suggested that the controller should not only rely on a df/dt input but should also incorporate a frequency trigger. Consideration was also given to a simple 'one-shot' control which would deliver a fixed volume of energy with a defined ramp and decay period when frequency reached a pre-defined setting.

2.10 The simple 'one-shot' control would not have the control complexities of a df/dt trigger but would not adapt to a specific frequency event after the initial frequency disturbance, potentially resulting in an uncontrolled response.

2.11 With regard to recovery periods, concerns were raised relating to the potential reduction in power output from wind turbines following the provision of increased active power output in response to a frequency fall.

2.12 A variable speed wind turbine relies on operating at the optimum point on the Cp - λ curve in order to extract the maximum available power from the wind. This is a complex non linear function and becomes a significant issue when the wind turbine is operating just below rated wind speed. In the event that the wind turbines are operating at just below their rated wind speed and at the same time, activation of the synthetic inertia control is required, then once the additional active power has been injected into the network, the recovery period can result in a drop in power output of up to 30% of its pre fault output, resulting in a frequency collapse after the event.

2.13 Figure 2 below shows an illustrative frequency trace using a power injection equivalent to 10% of non-responsive wind generation, with a 10% loss of output from the same plant after 10 seconds.

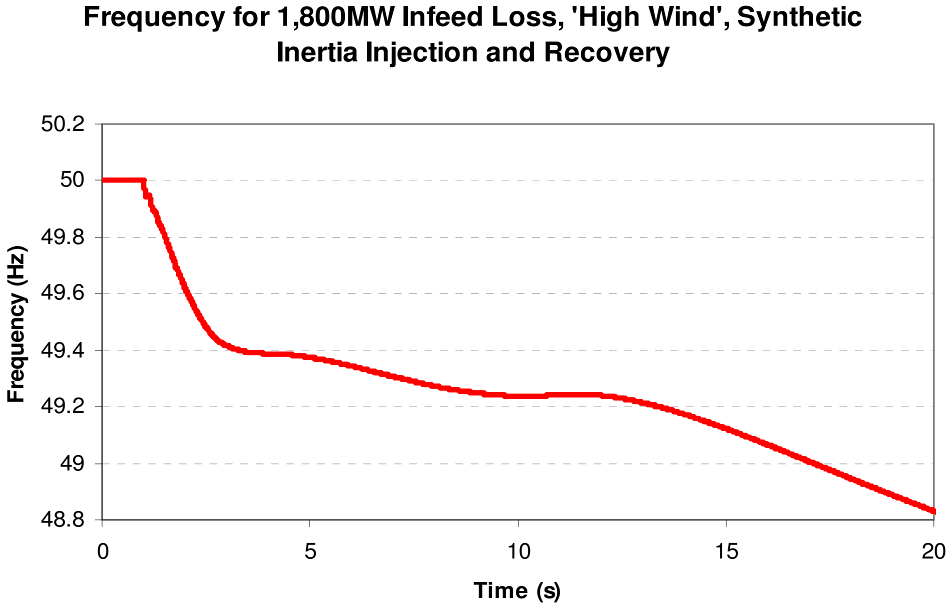


Figure 5: The effect of loss of active power output during the wind turbine 'recovery period'

2.14 In investigating this issue, a range of wind statistics was examined to determine the likelihood of a large volume of wind generation across the country operating at a similar wind speed. Data was also obtained to examine the effect of how wind speed varied within the wind farm.

2.15 The results of this analysis demonstrated that there was potentially a serious risk that a significant volume of geographically dispersed generation could be operating at a similar wind speed. The only guaranteed solution to this would be for the wind generation to be curtailed pre-fault, reducing the rate at which emission savings can be delivered.

2.16 An alternative approach to a synthetic inertia requirement would be to consider a method of rapidly injecting active power into the system following the loss of a generating unit by adopting a conventional proportional governor control.

2.17 This second approach was investigated using a response characteristic on frequency responsive wind generation that provided full primary Frequency Response within 5 seconds, being sustained for a further 25 seconds, rather than the current Grid Code requirement of delivery in 10 seconds and sustainable for a further 20 seconds.

2.18 The results of these studies demonstrated that the system frequency deviations could also be contained when 'Fast Frequency Response' was installed and that significant reductions in response requirements could also be achieved.

2.19 Discussions also highlighted concerns over the ability to deliver a synthetic inertia capability and conventional Primary Response from the same machines at the same time. It is therefore necessary to consider the likely generation patterns more carefully to check whether there is a sufficient amount of synthetic inertia capable plant which isn't already required to manage system frequency in Primary and Secondary response timescales.

2.20 In assessing the materiality of the issue, it is also important to consider the proportion of the time where a synthetic inertia requirement may be needed to allow National Grid to meet the frequency containment requirements of the SQSS. Initial simulations highlighted that achieving frequency containment was significantly more challenging at transmission system demands of 35GW and less. A review of transmission system demands for 2008 to 2010 suggests that this represents approximately 50% of the time.

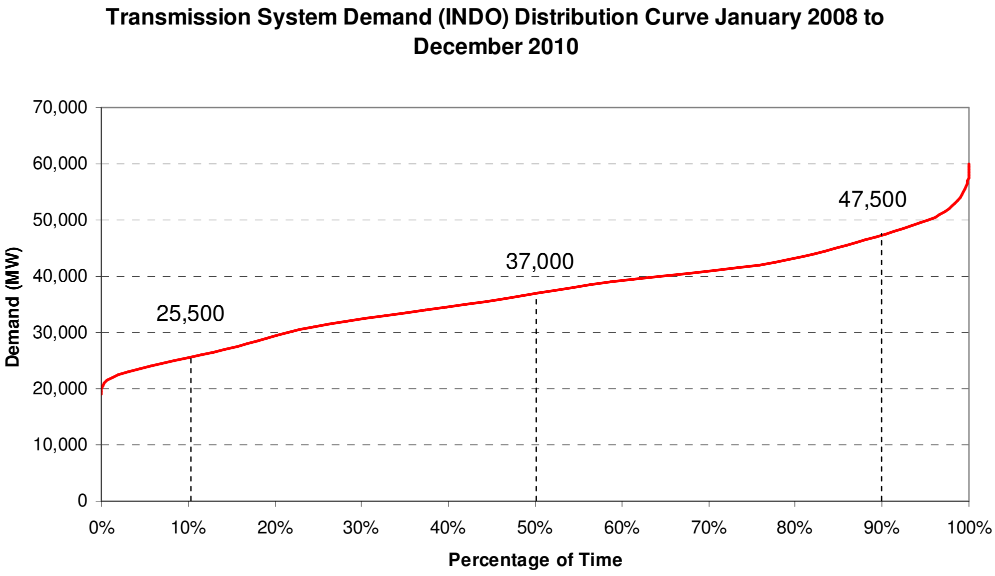


Figure 6: Transmission System Demand distribution curve

2.21 The next stage of analysis therefore needed to be based on clear demand and generation assumptions which are discussed in the next section.

3. Generation and Demand Scenarios

3.1 This section outlines how generation and demand scenarios were derived from which the final set of simulations could be based.

3.2 The starting point was to consider National Grid's Gone Green Scenario for the year 2020. Gone Green for 2020 embodies a generation capacity of 100GW, made up of 11GW nuclear, 27GW of wind, 50GW of fossil fuelled plant, 3GW of Pumped Storage, 6GW of Interconnectors, and 3GW of other renewables.

3.3 An individual generation pattern was developed for each demand level, and with a High, Average and Low wind resource. The wind resource levels incorporated in the scenarios were less at the lower demand levels than at the high, in line with observed wind load factors which are on average greater at high demand levels, and lesser at lower demand levels.

3.4 It is recognised that these wind resource assumptions do not capture the full range of possible wind conditions, but they do allow simulations to be constructed which illustrate how wind output assumptions impact on the generation mix and hence Frequency Response.

3.5 Each individual generation scenario was constructed by first examining the amount of generation which was likely to make the commercial decision to run at base load, a category made up mainly of nuclear and wind generation.

3.6 Next, a Primary Response requirement was estimated, including an assumed contribution to Primary Response from Low Frequency Relay triggered demand. The generator response volumes assumed in this exercise are given in Table 1 below.

3.7 The net response requirement was then apportioned to the available generation in the following order:

- Response was first allocated to fossil fuelled synchronous generation at a loading level of 85%, the loading point where, on average, the most effective ratio of response to deload is delivered. For demand scenarios above 35GW, this generation is generally already required to meet demand.

- Where the estimated response requirement could not be met on synchronous generation at 85% (ie generation exceeded demand), then plant was loaded at lower levels, giving more response per machine.

- If the response requirement could not be met using synchronous generation alone, response was allocated to asynchronous generation starting at 85%, with load reduced as necessary.

3.8 Additional balancing actions (such as synchronising additional generation) were also considered if necessary.

3.9 The generation scenarios constructed using this process were then used as a basis for individual simulations for each system demand level and wind resource assumption. The scenarios were then adjusted until the resulting simulated frequency trace was satisfactorily close to the target frequency of 49.2Hz when the system was subject to its largest loss.

3.10 All scenarios were derived as a single snapshot in time, and did not take into account any other system issues such as network constraints. Some of the approaches used to solve the Primary Response requirement problem may not be achievable in practice.

3.11 The spreadsheet used to represent the plant mix and generation background is shown in Annex 6.

3.12 Response volume assumptions were derived from information on recently commissioned generation. Ramp rate assumptions were then derived by calculating the rates necessary to achieve the required volumes. These are shown in Table 1 below.

Load Point (pu wrt Active Power)	Response Delivered (pu)	Response/ Deload	10 Second Ramp Rate (pu/s)	5 Second Ramp Rate (pu/s)
0.55	0.125	28%	0.0139	0.0313
0.65	0.125	36%	0.0139	0.0313
0.75	0.125	50%	0.0139	0.0313
0.85	0.082	55%	0.0091	0.0205
1.00	0	0%	0.0000	0.0000

Table 1: Frequency Response volume, delay and ramp rate assumptions

4. System Models to assess Frequency Response Requirements

4.1 In order to assess the future Frequency Response requirements, the following model shown in Figure 4 was constructed in Digsilent Power Factory.

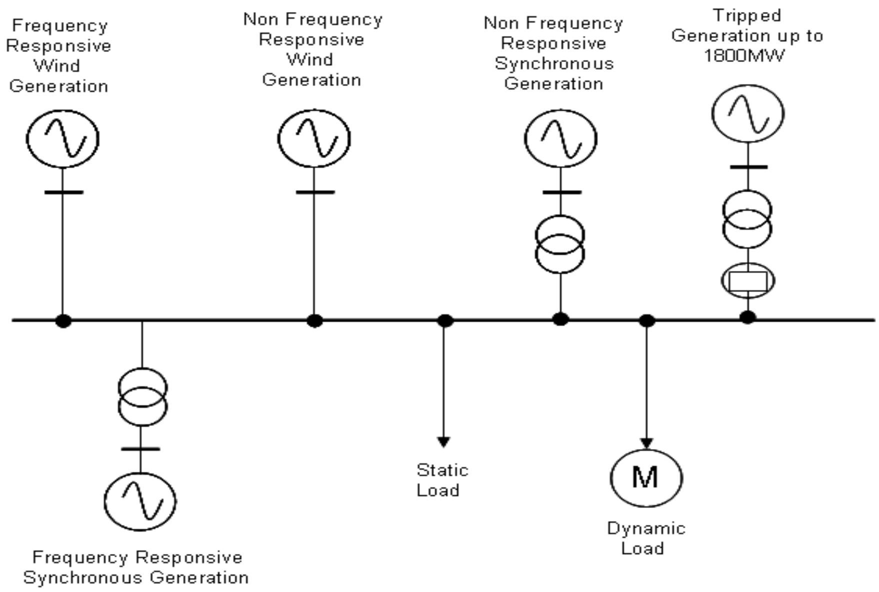


Figure 7: Model used to assess Frequency Response requirements

4.2 The model comprises of non frequency responsive synchronous and asynchronous generation together with frequency responsive synchronous and asynchronous generation.

4.3 The governor models used on the synchronous plant are generic but provide a representative reflection of aggregated plant behaviour. The models incorporate a droop characteristic, a ramp rate limit, amplitude limit and delay. The same parameters were used to represent both synchronous and asynchronous plant following a review of current plant capability.

4.4 The load was segregated into two components, namely a dynamic element (including a linear component and damping component) and a static element. These are important as some load relief will be realised as the frequency changes. The maximum generation loss was initially set at 1,800MW to reflect the increased loss in the SQSS but could be varied.

4.5 This single busbar, lumped machine model was considered adequate for the simulations required to investigate system wide synthetic inertia and Primary Response requirements. Local and distributed effects could not be investigated using this model and should be examined more carefully in future work.

5. Evaluating Primary Response Requirements

5.1 As described above, simulations were conducted for each demand and generation pattern and adjusted until the resulting simulated frequency trace was satisfactorily close to the target frequency of 49.2Hz when the system was subject to its largest loss. Figure 5 below illustrates how the time of the frequency minimum reduces as demand and hence inertia reduces.

Changing Rate of Simulated Frequency Fall for 1,800MW Infeed Loss - Low Wind

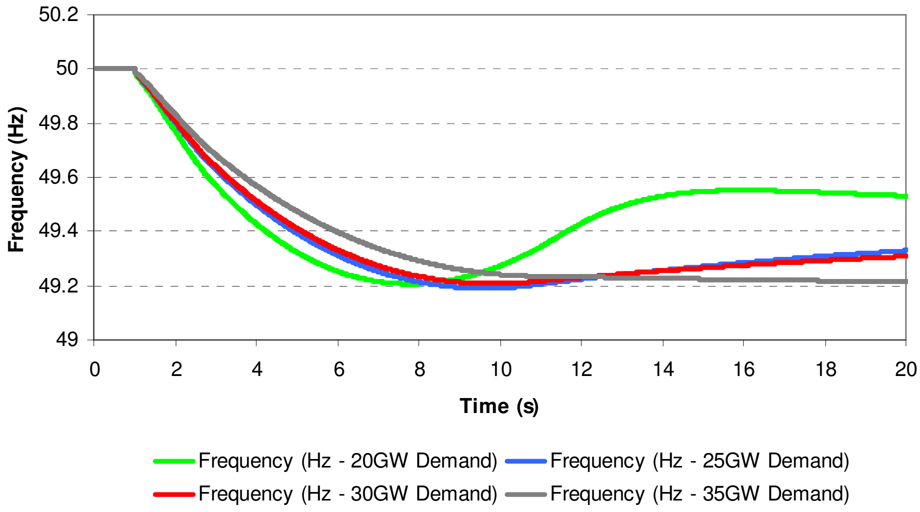


Figure 8: Changing rate of frequency fall with reducing demand

5.2 Where the frequency minimum point falls before 10 seconds after the infeed loss event (which occurs at one second in these simulations) care needs to be taken when deriving the Primary Response required to achieve containment. Rather than simply looking at the response delivered, it is necessary to back-calculate the response scheduled by referencing the machine loading point against the response that would have been delivered at the 10 second point.

5.3 Figure 6 below shows the response delivered by synchronous generators in the 20, 25 and 35GW simulations for Low Wind conditions. In these examples, the responsive generators (in the case of the 25 and 35 GW simulations) are loaded at 85% of their active power capability, and 75% (in the case of the 20 GW simulation).

5.4 The scheduled response is therefore equivalent to the value given in Table 1 multiplied by the active power rating of the machine. In the case of the 25GW and 35GW simulations, this is 8.2% of the loading point divided by 0.85. In the 20GW simulation, the loading point is reduced to 75% to get the additional response required, therefore the response scheduled is 12.5% of rating, which is equivalent to the machine loading divided by 0.75.

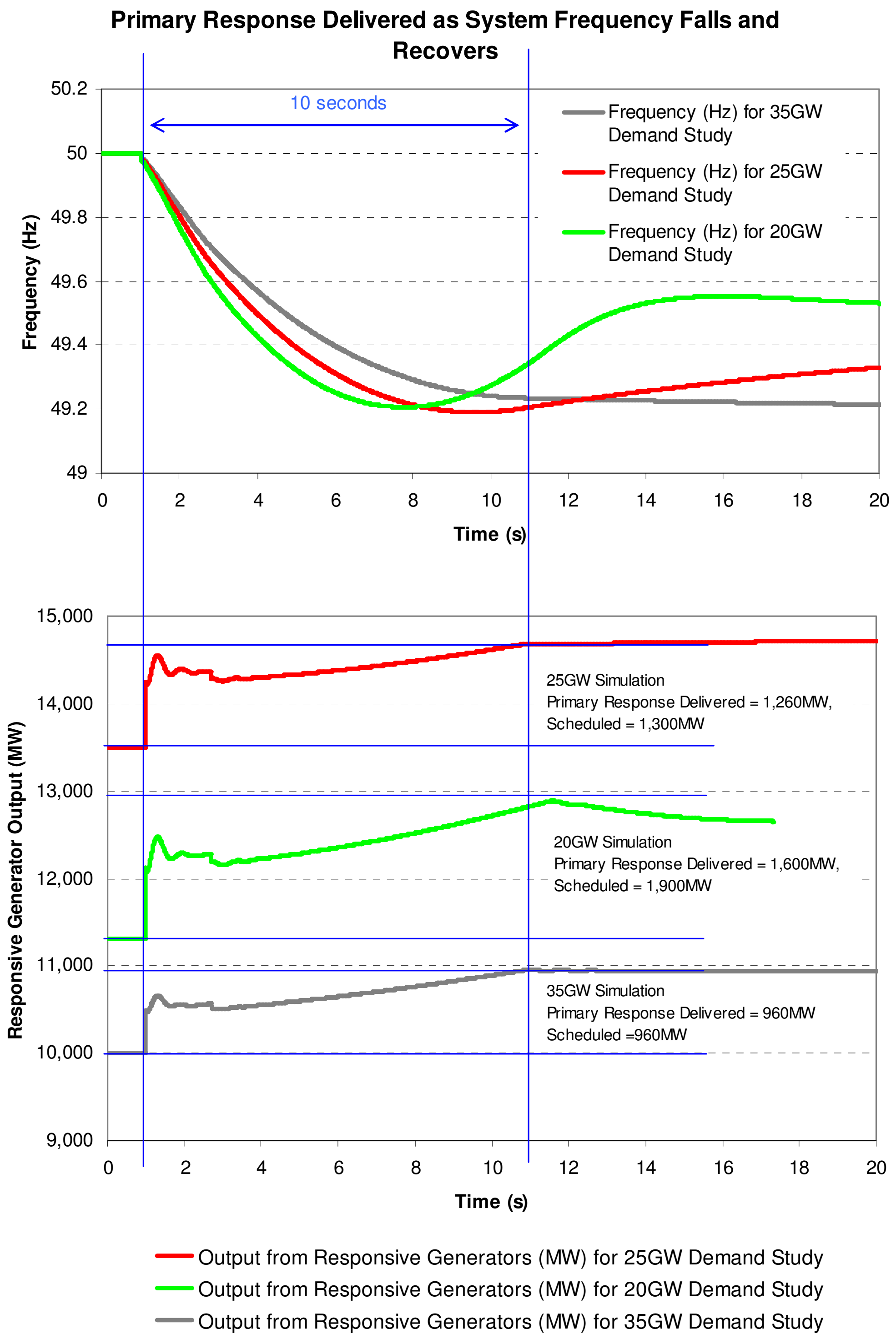


Figure 9: Primary Response Delivery Profile

5.5 As the rate of frequency fall increases, the discrepancy between the amount of response scheduled and the response that is delivered at the time required increases. This means that as the rate of frequency fall increases such that it interacts with responsive generators ramping, the requirement for primary Frequency Response increases in line with the assumed ramp rate as well as with the change in system characteristics.

6. Sensitivity to Primary Response Assumptions

6.1 Simulations were carried out using a governor characteristic where the expected volume of Primary Response was delivered over 10 seconds, with a delay of 1 second before Frequency Response was initiated. A linear ramp over the next 9 seconds was assumed. Figure 7 below shows how changing the delay assumption to 3 seconds (with ramping over 6 seconds) results in the non-compliant frequency trace shown in red.

6.2 In this example, additional response of 500MW had to be scheduled in order to achieve compliance with a 3 second delay.

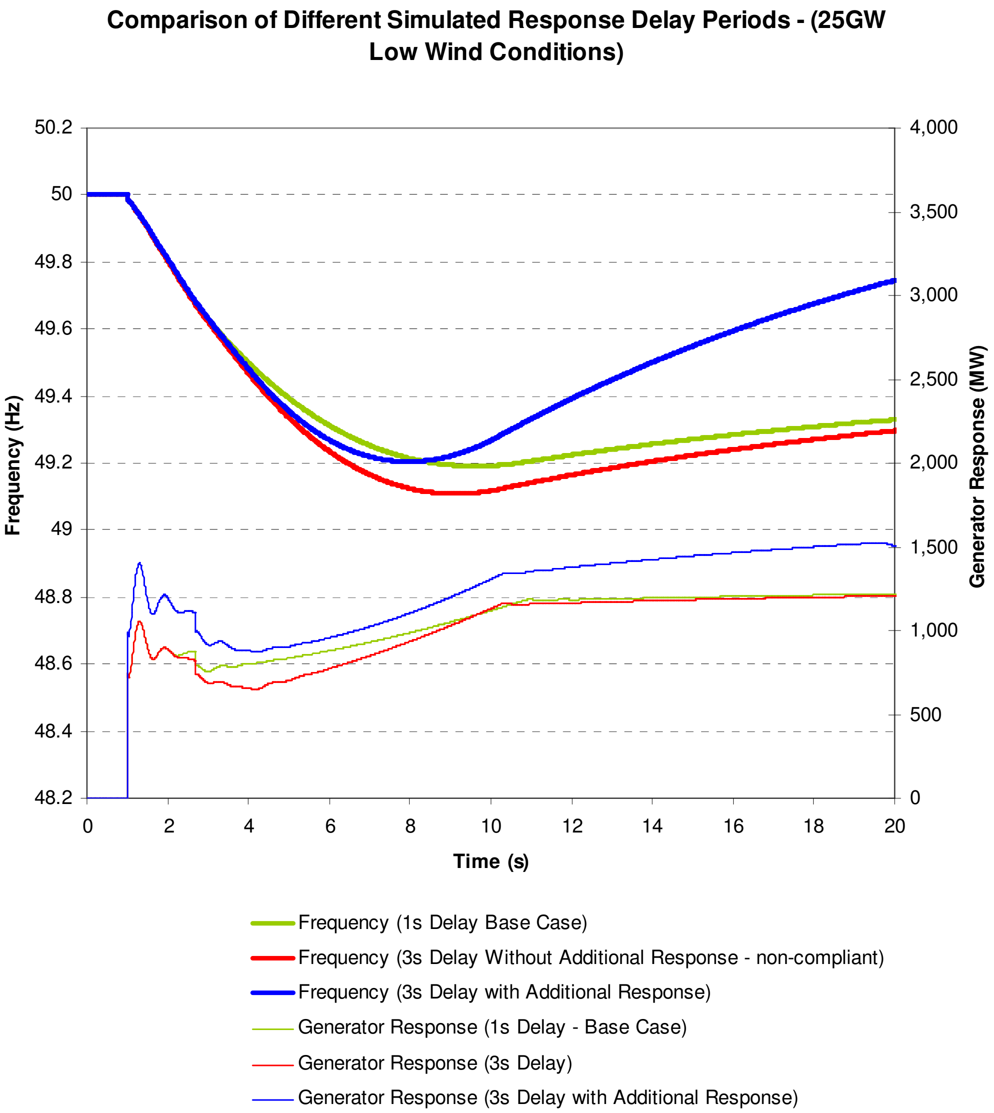


Figure 10: Comparison of Response Delay Periods

7. Frequency Response Erosion

7.1 The historic approach to setting Primary Response requirements is to check compliance for a frequency deviation to 49.2Hz, with a starting frequency of 50Hz. In practice, it is necessary to take account of uncertainties in the simulation and also to consider the effects of starting at frequencies lower than 50Hz. A margin is then added to the requirements to reflect this. This effect becomes more important as larger volumes of dynamic response are scheduled.

7.2 Figure 8 below shows the impact of a large infeed loss when the initial frequency is low. An imbalance was introduced to the simulation to set the initial frequency at approximately 49.9Hz before the large infeed loss

7.3 occurred. In this case, an additional 200MW had to be scheduled (on top of the ~1,000MW required in the base case simulation) to ensure that the region in which there is a risk of Low Frequency Demand Disconnection of operating was not encroached upon.

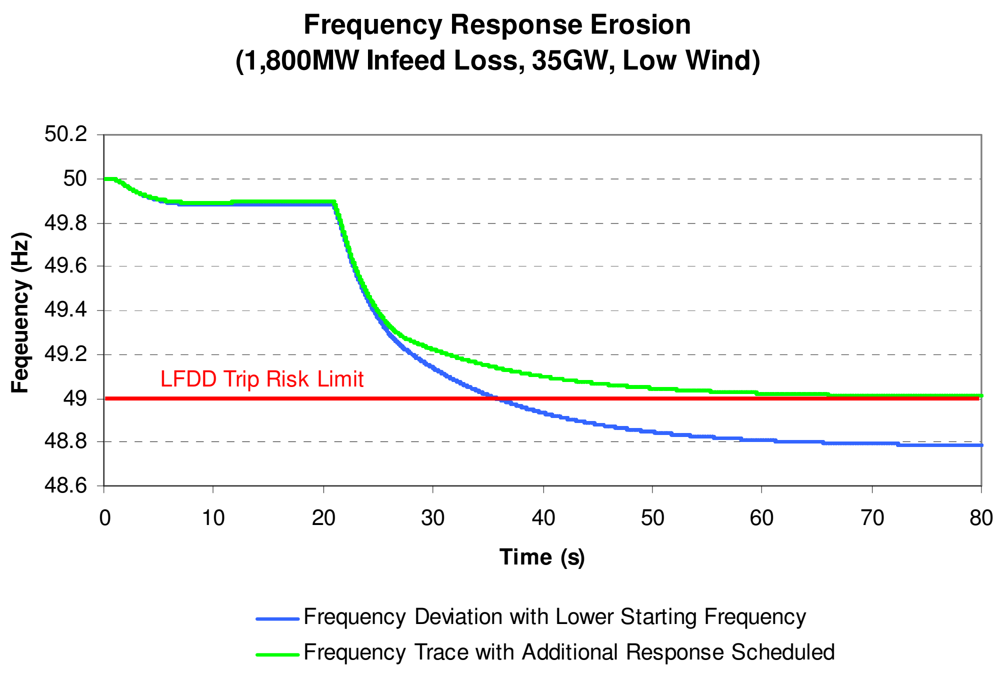


Figure 11: Frequency Response Erosion

7.4 Therefore, in order to cater for the erosion risk, a factor of 20% has been applied to the requirements presented in this report where these are met by 'dynamic' response sources (ie not 'static' frequency triggered demand control). Further work is required to derive a margin which is robust in all relevant cases.

8. Response Requirements

8.1 This section sets out the Primary Response volume requirements that have been derived by simulation for an 1,800MW infeed loss and for a 1,320MW infeed loss. Requirements are given for the demand and generation backgrounds described in the 'demand and generation' section above and detailed in Annex 6 up to a transmission system demand of 55GW. At demands higher than 55GW, the simulated rate of frequency fall was such that containment was required in secondary response timescales only.

1,800MW Infeed Loss - *Low Wind*

8.2 Figure 9 below shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under Low Wind conditions. At low system demands the Primary Response requirement is seen to increase noticeably. This is caused by the frequency fall coinciding with frequency responsive generation ramping.

8.3 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds. It should be noted that the effect of low frequency triggered response was very effective at arresting the fall in system frequency.

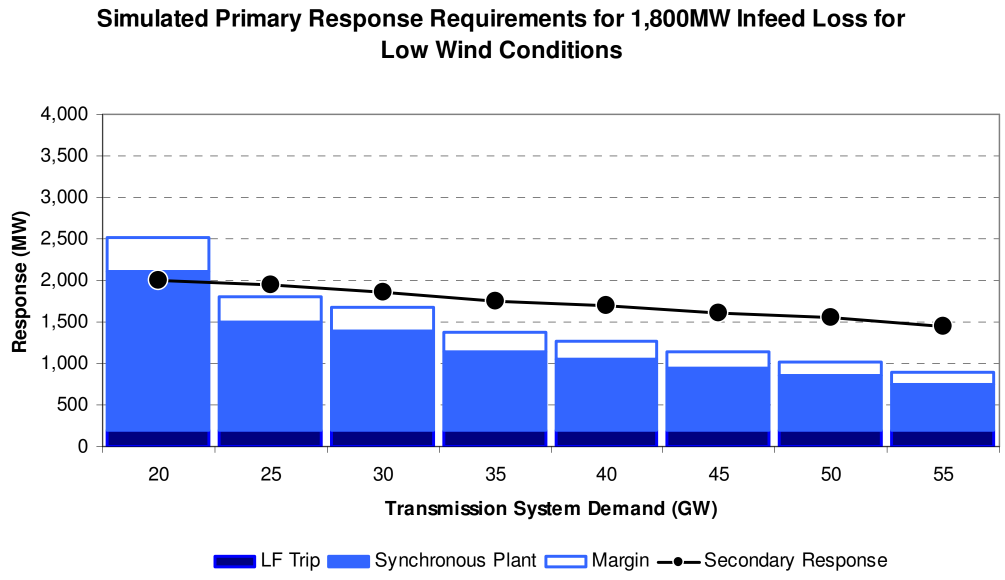


Figure 12: Primary Response Requirements, 1,800MW Loss, Low Wind

8.4 The secondary response requirement is also shown. In general terms, where the Primary response requirement is higher, this means that additional balancing actions need to be taken purely to meet the Primary Response requirement.

1,800MW Infeed Loss - Average Wind

8.5 Figure 10 below shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under Average Wind conditions. Again, the increased requirement can be seen at lower system demands.

8.6 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds, apart from the 20GW simulation. In this case, asynchronous generation was used to make up the balance of the response requirement.

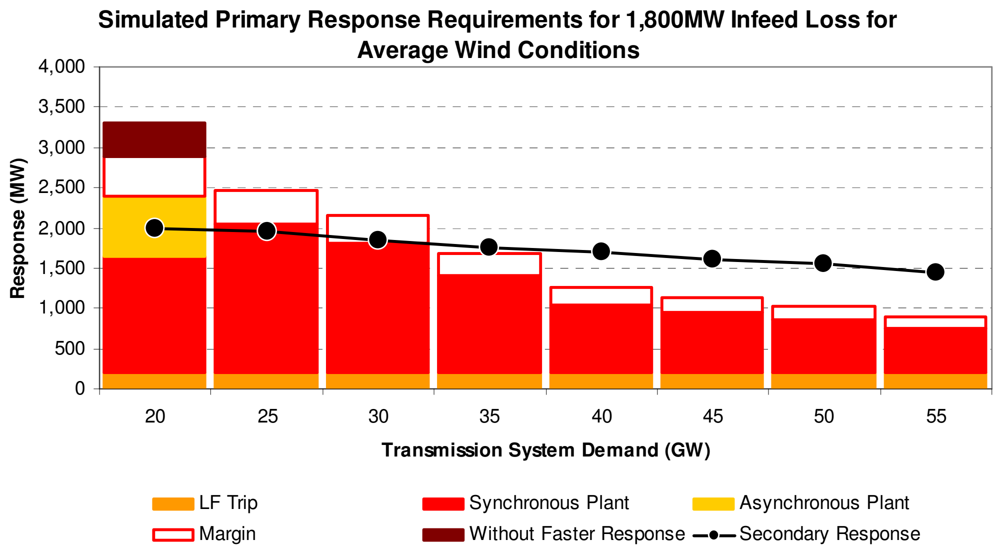


Figure 13: Primary Response Requirements, 1,800MW Loss, Average Wind

8.7 Two approaches were applied, one with asynchronous response delivered in 5 seconds (ie fast response) and one in 10 seconds. The difference between the two was equivalent to approximately 400MW of Primary Response.

1,800MW Infeed Loss - *High Wind*

8.8 Figure 11 shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under High Wind conditions. Again, the larger requirement can be seen at lower system demands. Low frequency triggered response of 200MW was again incorporated in all simulations apart from the 20GW simulation where 350MW was utilised. The balance of Primary Response came from synchronous generation, delivered in 10 seconds, for simulations at 40GW and above. In the other cases, asynchronous generation was used to make up the balance of the response required.

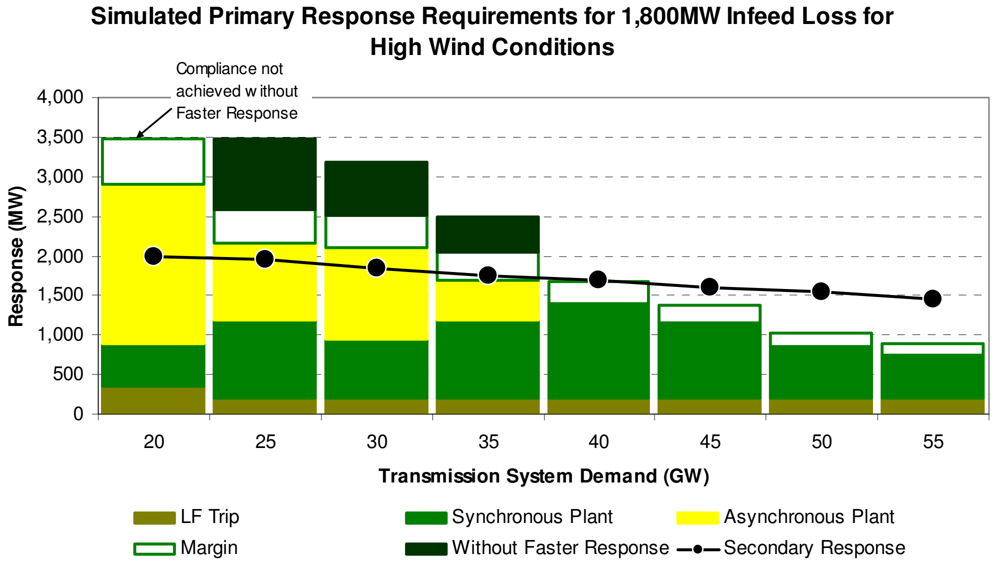


Figure 14: Primary Response Requirements, 1,800MW Loss, High Wind

8.9 Again, two approaches were applied, one with asynchronous response delivered in 5 seconds and one in 10 seconds. The difference between the two was equivalent to between 450MW and 900MW of Primary Response.

8.10 Frequency containment could not be achieved for the 20GW simulation in the absence of Fast Frequency Response. The frequency trace is shown in Figure 12.

8.11 The 20GW simulation also yielded the highest Rate of Change of Frequency at -0.68Hz/s. Further work is required to assess whether this has any impact on the deployment of Rate of Change of Frequency based protection for the purposes of loss of mains protection.

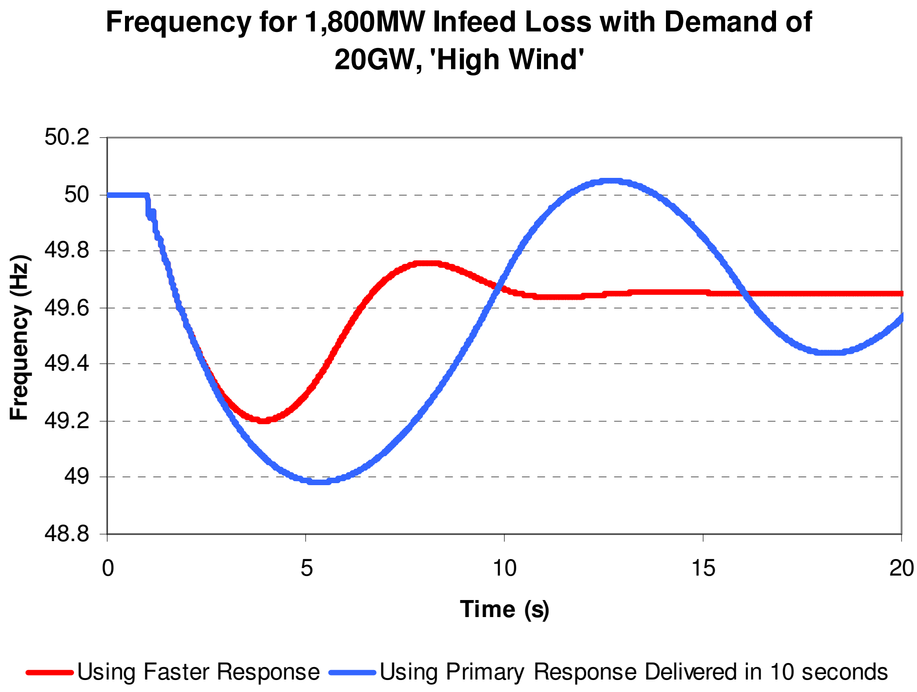


Figure 15: Frequency for 1,800MW Loss at 20GW, High Wind

1,320MW Infeed Loss - *Low Wind*

8.12 A similar process was followed to examine the primary Frequency Response requirement for a 1320MW infeed loss. In this case the SQSS stipulates that frequency should be contained to 49.5Hz rather than 49.2Hz.

8.13 The simulated Primary Response requirements for a 1,320MW Infeed Loss under Low Wind conditions are shown in Figure 13.

8.14 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds.

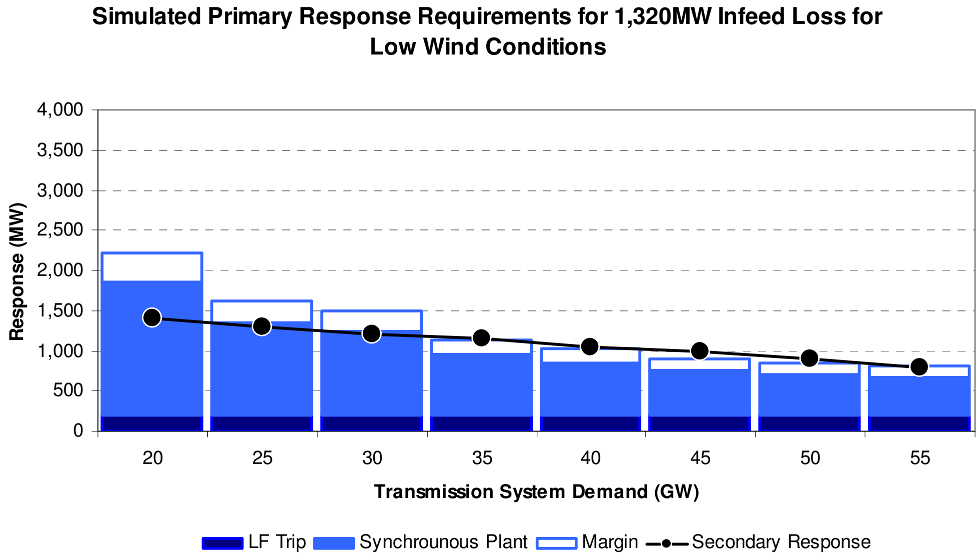


Figure 16: Primary Response Requirements, 1,320MW Loss, Low Wind

1,320MW Infeed Loss - *Average Wind*

8.15 Figure 14 shows the simulated Primary Response requirements for a 1,320MW Infeed Loss under Average Wind conditions.

8.16 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds, apart from the 20GW simulation. In this case, asynchronous generation was used to make up the rest of the response requirement.

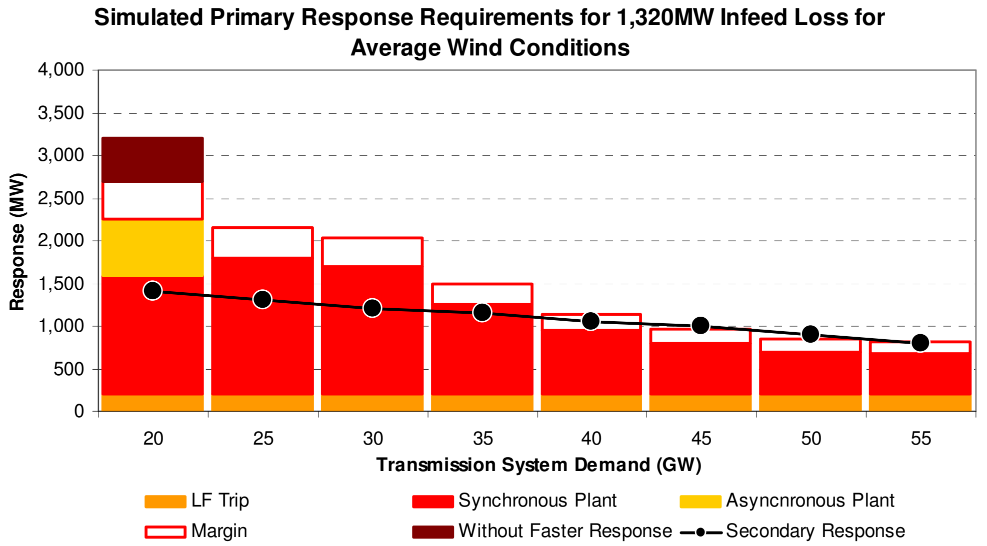


Figure 17: Primary Response Requirements, 1,320MW Loss, Average Wind

8.17 As in the case of the 1,800MW infeed loss, two approaches were applied, one with asynchronous response delivered in 5 seconds (ie fast response) and one in 10 seconds. The difference between the two was equivalent to approximately 500MW of Primary Response.

1,320MW Infeed Loss - *High Wind*

8.18 The simulated Primary Response requirements for a 1,320MW Infeed Loss under High Wind conditions are illustrated in Figure 15.

8.19 Low frequency triggered response of 200MW was incorporated in all simulations apart from the 20GW simulation where 350MW was utilised. Primary Response synchronous generation, delivered in 10 seconds, was sufficient to contain the frequency deviation for simulations at 40GW and above. In the other cases, asynchronous generation was used to make up the rest of the response requirement.

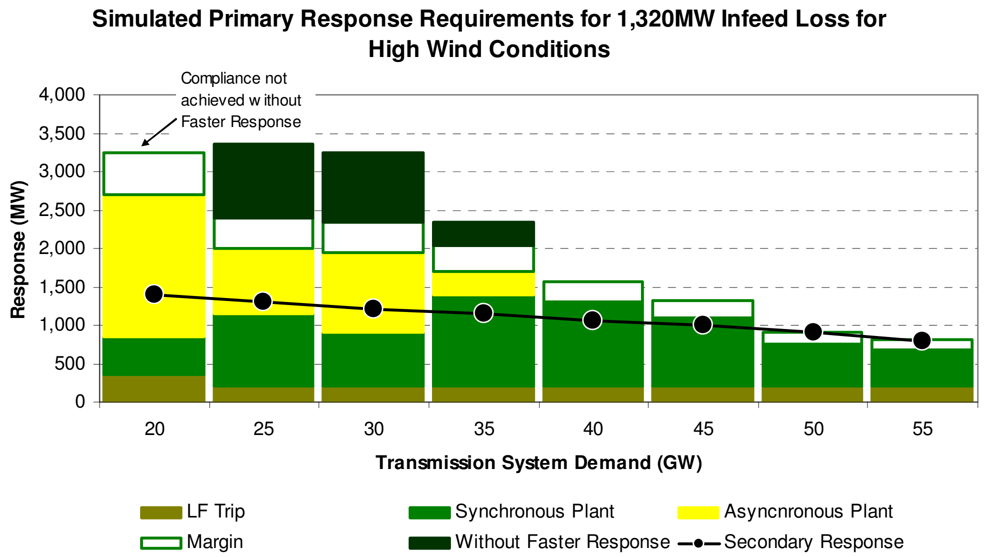


Figure 18: Primary Response Requirements, 1,320MW Loss, Low Wind

8.20 Again, two approaches were applied, one with asynchronous response delivered in 5 seconds and one in 10 seconds. The difference between the two was equivalent to between 300MW and 950MW of Primary Response. Containment could not be achieved in the 20GW simulation without fast response.

Summary of Low Frequency Response Requirements

8.21 Table 2 and Figure 16 provide an overall summary of the response requirement derived by simulation for Low, Average and High Wind conditions.

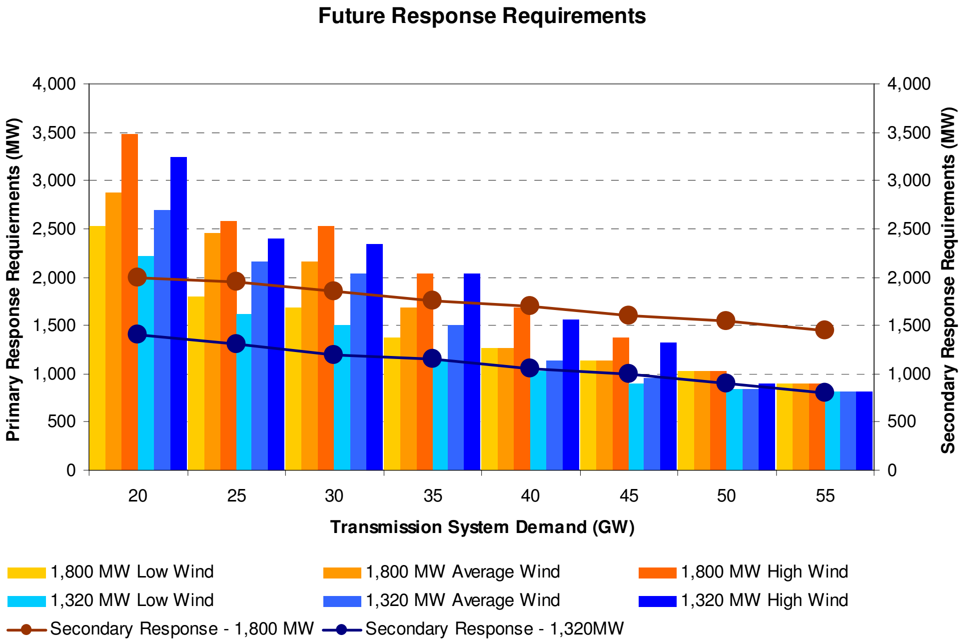


Figure 19: Future Low Frequency Response Requirements

		System Demand (GW)							
		20	**25**	**30**	**35**	**40**	**45**	**50**	**55**
Primary Response Requirement									
Low Wind	**1,800 MW**	2,520	1,800	1,680	1,380	1,260	1,140	1,020	900
	1,320 MW	2,220	1,620	1,500	1,140	1,020	900	840	810
Average Wind	**1,800 MW**	2,880	2,460	2,160	1,680	1,260	1,140	1,020	900
	1,320 MW	2,700	2,160	2,040	1,500	1,140	960	840	810
High Wind	**1,800 MW**	3,480	2,580	2,520	2,040	1,680	1,380	1,020	900
	1,320 MW	3,240	2,400	2,340	2,040	1,560	1,320	900	810
Secondary Response Requirement									
	1,800 MW	2000	1950	1850	1750	1700	1600	1550	1450
	1,320 MW	1400	1300	1200	1150	1050	1000	900	800

Table 2: Future Low Frequency Response Requirements

9. High Frequency Response Requirements

9.1 A range of simulations were carried out to examine High Frequency response requirements. Volumes have not been calculated for the purposes of this report. However, many of the issues highlighted for Primary Response above are the same for High Frequency response.

9.2 Figure 17 shows a simulated frequency trace for a 1,400MW demand loss which shows that the maximum frequency point occurs at less than 10 seconds. This highlights that the issues of ramp rate, delay and response volume discussed above in relation to Primary Response are equally valid for High Frequency response.

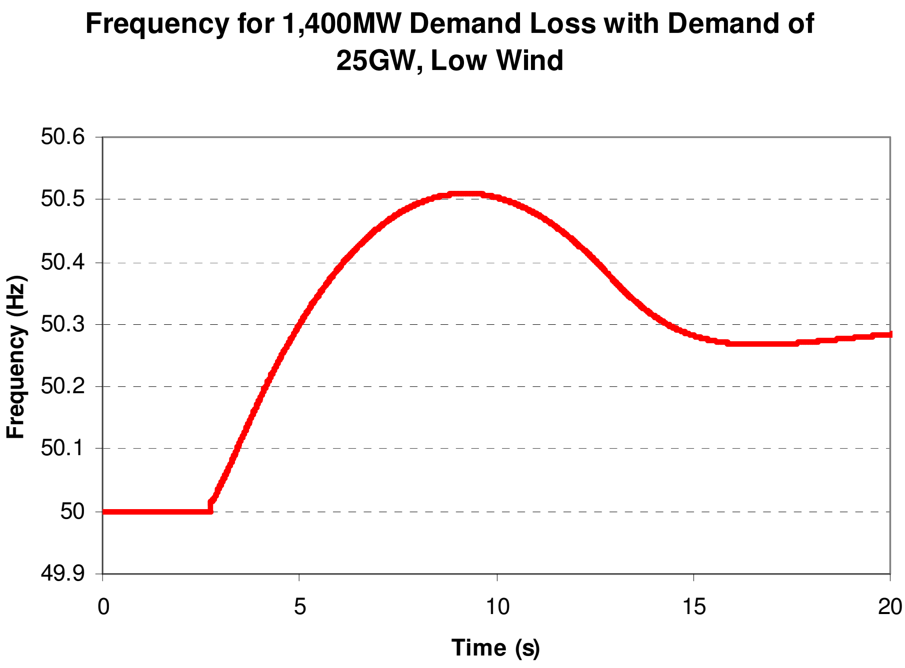


Figure 20: Frequency for 1,400MW Demand Loss

10. Impact of Varying Primary Response Timescales

10.1 The Primary Reponse requirements outlined above enable comparison to be made between requirements derived where response from asynchronous plant is delivered within 5 seconds and the requirements where all primary response from generation is delivered in 10 seconds.

10.2 The 5 second delivery time was initially selected based on the time that system frequency reached its minimum in simulations for the 20GW demand scenario. Further simulations were performed to investigate the benefit delivered as Primary Response timescales are reduced from 10 seconds.

10.3 Figures 18 and 19 show how the Primary Response requirement reduces as delivery timescales on asynchronous plant are reduced, using a 25GW and 35GW 'High Wind' generation and demand pattern.

10.4 The Primary Response requirement is shown at varying response delivery timescales alongside the reduction in requirement compared to the current 10 second criteria.

10.5 The incremental reduction (the reduction in requirement achieved by speeding response up by one second) is shown in the line plot on the secondary axis. In the cases investigated here, the incremental improvement reaches its peak value where response is delivered in 4 or 5 seconds.

10.6 Response rates of less than 5 seconds deliver less incremental benefit under these simulated conditions and would be expected to be more challenging to implement. Note that the 20% margin applied to the requirements in the sections above has not been applied in this analysis.

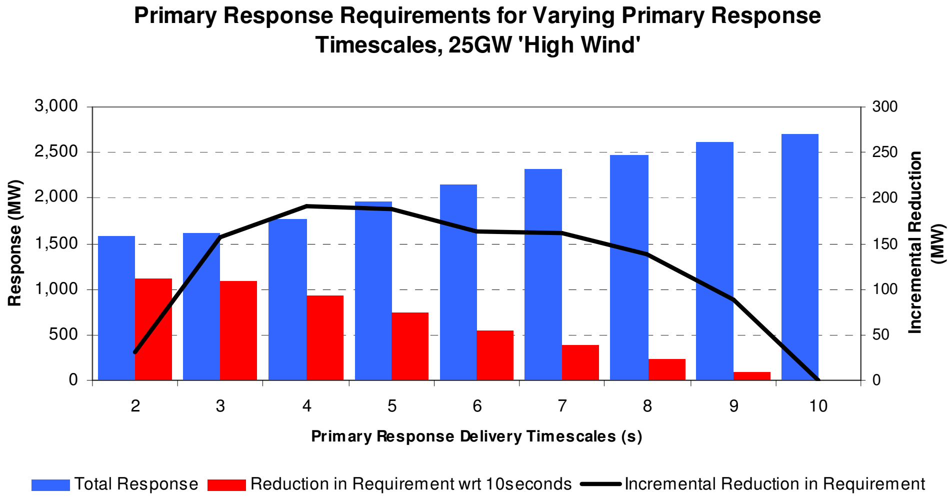


Figure 21: Varying Primary Response Timescales at 25GW system demand

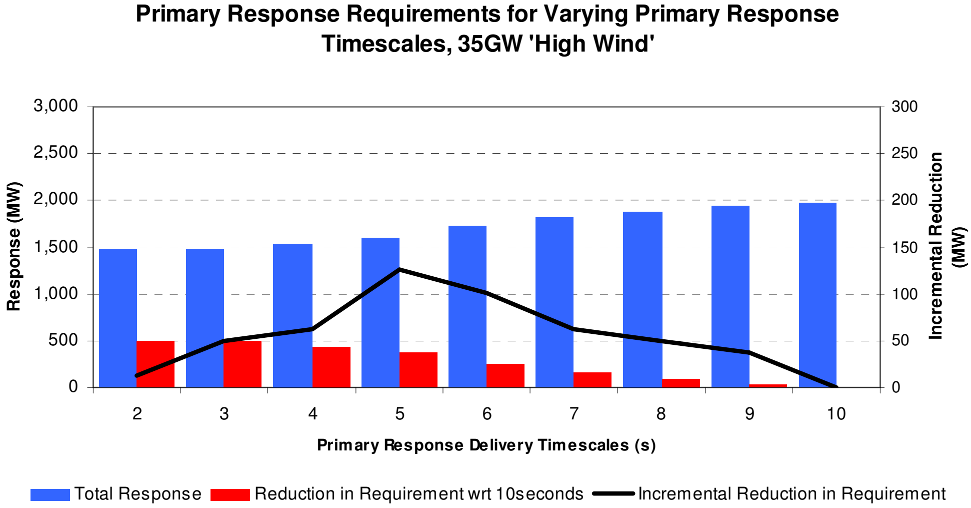


Figure 22: Varying Primary Response Timescales at 35GW system demand

11. Manufacturer Feedback

11.1 Wind turbine manufacturers played an active role in Technical Subgroup discussions, providing a great deal of useful guidance to the group. A number of points were raised within discussions including:

- the need for clarity and uniformity in requirements;
- timescales to develop equipment to meet new requirements; and
- the need to consider local and distributed system issues when specifying control system requirements.

11.2 The Technical Subgroup also discussed the synthetic inertia requirement developed in Canada which was understood to be similar to the 'one-shot' option discussed (with a power delivery profile thought to be suited to the Canadian system). Frequency response requirements in Ireland were also debated. These were understood to focus on faster delivery of Primary response, similar to the 5 second criteria already being discussed in the Technical Subgroup.

11.3 It should however be noted that some areas of equipment capability could not be discussed fully within the Technical Subgroup. National Grid therefore sought confidential feedback on a range of questions relating to Synthetic Inertia and Fast Frequency Response. Replies were received from 5 wind turbine manufacturers and one HVDC manufacturer.

11.4 All of the replies from wind turbine manufacturers stated that Fast Frequency Response (in 5 seconds) could be delivered by wind turbines with the exception of one, who stated it was not possible to confirm this at this time.

11.5 A number of replies highlighted that the delivery of Frequency Response by wind turbines was dependant on the wind resource available.

11.6 No specific implementation costs were provided but a number of the replies stated that development costs for them were likely to be associated with software and control systems rather than in turbine hardware.

11.7 Some replies indicated an implementation time, with the minimum quoted at 18 months, maximum at 2 years.

11.8 A number of replies also highlighted a desire to continue development work on a synthetic inertia. One also highlighted the potential benefits of synthetic inertia where its provision could mean that curtailment of wind would be minimised.

11.9 None of the respondents felt able to make specific comment on the provision of synthetic inertia or fast primary response on offshore networks connected via HVDC. However, one reply stated that the desired response timescales were well within the capabilities of current HVDC technology, providing an energy source was available.

12. Conclusions

12.1 In order to manage the Transmission System in the future and ensure system frequency can be managed to the criteria set out in the SQSS, there will be a requirement to mitigate the reduced contribution to system inertia from decoupled generation plants such as variable speed wind turbines and other static plant such as HVDC Converters.

12.2 The following conclusions were drawn from National Grid's simulations based on a 'Gone Green' generation scenario for the year 2020:

- A supplementary frequency control facility can deliver significant benefits in managing the 1,800MW and 1,320MW infeed risk at system demand levels of 35GW and below under all but "Low Wind" conditions.

- The measures needed to ensure compliance with the SQSS, and avoid impacting on system security, become more severe and more significant in volume as system demand, and the capacity of any synchronous generation meeting it, decreases;

- Additional low frequency relay triggered demand response was required as well as supplementary frequency control capability to achieve frequency containment at system demands of 20GW under 'High Wind' conditions;

- These factors suggests that both a supplementary frequency control capability and alternative actions will be required to ensure frequency containment can be achieved at demands of less than 25GW. Further alternative actions include:

  - Curtailment of the largest infeed loss; and

  - Additional balancing actions, such as:

    - curtailment of interconnectors or inflexible plant;

- displacement using plant with additional response capability;
- fast acting low frequency relay triggered response; and
- addition of inertia, by 'low load operation' on synchronous generation for example.

12.3 It should be noted that the simulations were based on an interconnector position of 'float' (ie no import/export) and that any net interconnector import has the effect of displacing synchronous plant. There is currently 3.5 GW of interconnector capacity on the transmission system, a variability of 7GW. It should however be noted that the volume of interconnectors to Great Britain may increase in the future.

12.4 A number of supplementary frequency control capability options were investigated, including a pure 'df/dt' driven fast acting control on un-curtailed asynchronous plant which is intended to mimic the inertia capability of a synchronous machine. This form of control provides an ideal solution, as it helps solve the frequency control problem without the need to curtail wind. However, there are a number of issues associated with it:

- Any control system will incorporate a processing delay which needs to be limited to ensure the desired effect is achieved;
- Rate of Change of Frequency as an input parameter is inherently noise amplifying leading to unpredictability of response;
- Care needs to be taken not to extract too much energy from wind turbines as this can lead to an extended and detrimental recovery period, particularly at specific points on the wind turbine operating curve. This leads to some uncertainty over the volume and timescales of energy available; and
- Discussions suggest that wind based Power Park Modules will find it difficult to deliver both a 'df/dt' driven fast acting control and Primary Response consecutively with the volumes required. This issue is critical as work to date suggests that both are required under most of the relevant system scenarios.

12.5 Alternative synthetic inertia controllers based on Rate of Change of Frequency, using fixed and variable volumes were investigated. It was demonstrated that these options provided a potential solution to the frequency containment problem, provided that the correct volumes and characteristics could be specified. These would need to be validated for the full range of possible future system conditions.

12.6 Finally, the option of using faster acting proportional frequency control was investigated by taking a conventional Primary Response characteristic and adapting it to deliver response within 5 seconds rather than 10. This characteristic was applied to wind generation which was already curtailed in order to provide conventional Primary Response within the simulations described in this report.

12.7 This capability had the effect of reducing the Primary Response requirement and hence the need to curtail renewable generation significantly. A benefit of between 400MW and 950MW was observed in the simulations presented in this report. If one assumes that this benefit applies for 10% of the year at an average of 500MW and response price of

12.8 30 £/MW/h, a benefit of £13m per year in balancing cost could be attributed to this capability. There would be an additional carbon benefit for the wind curtailment avoided.

12.9 Based on the analysis conducted, it has been concluded that the single change to response provision that would yield the most significant benefit is through the introduction of a fast primary Frequency Response capability applicable to all decoupled generation sources which do not naturally provide an inertial contribution.

12.10 Such generating plant should have the capability to provide 10% or more of its registered capacity as primary Frequency Response which should be delivered linearly over a 5 second period from the inception of the generation loss or load change and an initial delay of no more than 1 second from the inception of the frequency change.

12.11 It is recognised that this specification may present a challenge to technology providers and manufacturers. However, it is believed that this specification is more achievable, at an earlier implementation date, than the df/dt triggered control option discussed above.

12.12 Simulations also showed a high degree of sensitivity to the ramp rate assumptions for Primary Response. It is recommended that these are specified explicitly within the Grid Code by setting out a maximum response delay of 1 second and specifying that response should be delivered linearly up to 10 seconds or 5 seconds as appropriate.

12.13 Whilst it is acknowledged that these proposals could resolve the issue for Plant in excess of 50MW, some consideration will still be required as to how this issue will be addressed in respect of Small Embedded Power Stations as this segment of the market is expected to grow in the future.

12.14 The studies have also demonstrated the effect on rate of change of system frequency against a credible set of future generating scenarios. As a conclusion it is seen that this will impact on Embedded Generation, in particular the effect on protection settings. It is therefore suggested that this report is highlighted to the Distribution Code Review Panel for further consideration in respect of Embedded Generation.

12.15 A final point to note is the extent of reliance on wind generation to deliver frequency control in the analysis performed in this report. Operators have little experience of this to date and it may be necessary to revisit the technical and commercial arrangements for the provisions of Frequency Response for asynchronous generators as more experience is gained.

12.16 Annex 7 contains text which sets out the very high level principles in addressing the need for a fast frequency response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency. The text has been drafted in the style of Grid Code change for illustrative purposes only.

13. Recommendations

Faster Frequency Response

13.1 Faster Frequency Response capability delivered within 5 seconds, for low and high frequencies, on users bound by the provisions of the Grid Code allows Frequency Response volumes to be reduced significantly in the situations analysed in this report.

(a) The value of faster Frequency Response should be assessed, taking into consideration the costs of implementation and the benefits in reduced curtailment of generation from renewable sources and other balancing costs; and

(b) Subject to this assessment, proposals should be developed for the appropriate obligations and/or market arrangements to ensure sufficient Frequency Response capability is available to maintain system security for anticipated future generation and demand patterns.

Clearer Primary Response Requirements

13.2 The simulations conducted by the Technical Subgroup have demonstrated the sensitivity of Frequency Response requirements to the ramping capability of responsive generation. The Grid Code requirements for Frequency Response should be reviewed with the aim of clarifying the ramping capability required from responsive generation in terms of:

(a) Adequacy of information provided on performance; and

(b) The need to stipulate minimum delay times and ramping capability for new providers.

Rate of Change of Frequency

13.3 The simulations performed by the Technical Subgroup give some indication to the potential change in the maximum Rate of Change of Frequency settings which needs to be considered in the context of the loss of mains protection deployed on embedded generation.

Annex 5 - Controller Descriptions

1.0 Synthetic Inertia Models

1.1 Two controllers were considered and tested. These being a one shot df/dt controller and a continuously acting df/dt controller. Both designs relied on Rate of Change of Frequency as a trigger signal. The reason being that Rate of Change of Frequency is a good measure as to the volume of generation lost. Clearly for the controller to work effectively it needs to know that the frequency has fallen and equally the rate of change of system frequency. For example, it would not appropriate to require the controllers to inject a fixed volume of active power irrespective of the generation loss as small generation losses could potentially result in temporary over frequencies and large generation losses could result in a risk of breaching the lower frequency limit. Both of these are controllers are described in detail below.

2.0 The One Shot df/dt Controller

2.1 The one shot df/dt controller is designed to inject an initial increase in active power following a frequency change in proportion to the Rate of Change of Frequency. The full active power injection should be available within 200ms and then decay exponentially over a period of Ts seconds. A small power recovery period of up to 5% of nominal power is permitted but limited to prevent the risk of subsequent frequency deviations following the initial generation loss or load change. An illustration of the control strategy is shown in Figure A1.0.

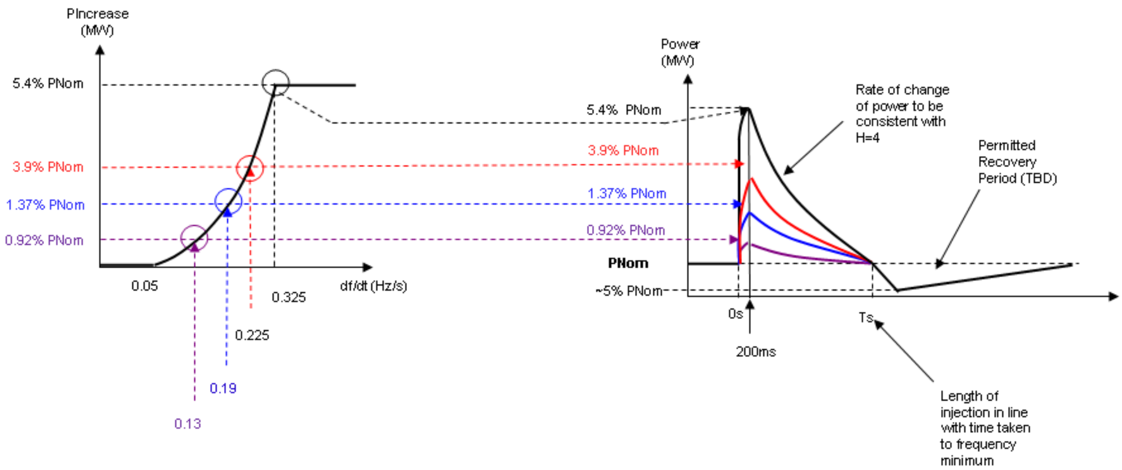


Figure A1.0

2.2 This control scheme was found to work well however, as the decay was exponential, ie generated by a mathematical function there was always a risk that the intended response would not be guaranteed if a subsequent event were to occur in the period between 0 – Ts seconds. For the purposes of the studies, a figure of 10 seconds was used although this was changed as a sensitivity. In addition, following discussions with manufacturers, the rise time of 200ms was debated as an issue as it would be difficult to implement using a df/dt controller. In respect of this, a number of sensitivity studies were run with different rise times to establish the effect on overall system frequency.

3.0 The Continuously Controlled df/dt Controller

3.1 The continuously controlled df/dt controller was developed to inject Active Power into the system in proportion to the rate of change of system frequency. In this event, the maximum active power would be injected then the rate change of system frequency is at its greatest. A representation of this controller is shown in Figure A2.0.

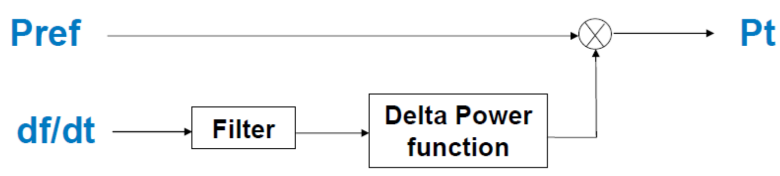


Figure A2.0

3.2 As with the one shot controller, this control system was also identified to work well ensuring that system frequency could be retained within statutory limits. Again, in response to questions raised at the working group, the delay time at which full active power was achieved from the inception of the frequency fall was examined and no major issues were identified with a 1 second delay time as shown in Figure A3.0.

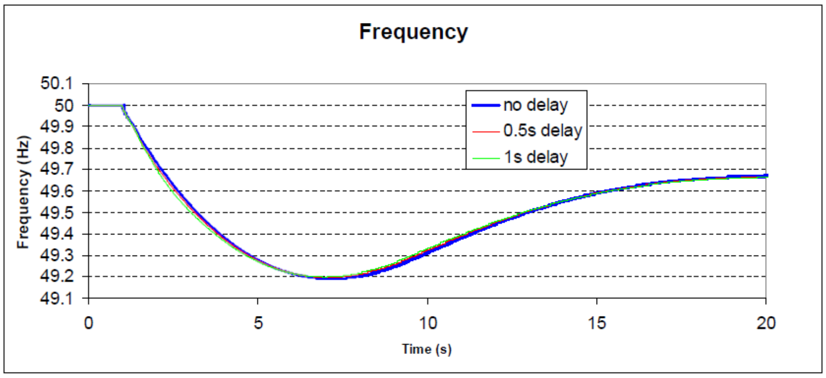


Figure A3.0

4.0 Rate of Change of Frequency as a Controlled Parameter

4.1 Both the one shot controller and continuously controlled df/dt controller utilised df/dt as an input parameter to provide the required response from the Wind Turbine. Whilst this is a good measure of how much generation has been lost or how much load has changed, unfortunately df/dt (being predictive) is a noise amplifying process which requires appropriate filtering, but equally can be triggered by non genuine generation losses such as switching incidents etc. In addition, as the control action would rely on the initial Rate of Change of Frequency, it would need to be quite fast acting and therefore the design of appropriate filtering becomes even more challenging.

4.2 In addition to the problems of df/dt as a control function, the problem of the recovery period as explained in references [1], [2] and [3] of this Appendix caused serious concerns to the adoption of a synthetic inertia controller. Since the issue could be resolved by the action of fast acting response, it was suggested that this would provide a better solution.

5.0 References

[1] Grid Code Review Panel Paper Reference pp10/21, Future Frequency Response requirements, dated September 2010.

[2] Contribution of Wind Energy Converters with Inertia Emulation to frequency control and frequency stability in Power Systems – Stephan Wachtel and Alfred Beekmann – Enercon – Presented at the 8th International Workshop on Large Scale Integration of Wind Power into Power Systems as well as on Offshore Wind Farms, Bremen Germany, 14 – 15 October 2009.

[3] Variable Speed Wind Turbines Capability for Temporary Over-Production – German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

[4] Study on Variable Speed Wind Turbine Capability for Frequency Response - German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

GG Year:2020

	Generation Capacities	Summer 20GW			Summer 25GW			Spring/Autumn 30GW			Spring/Autumn 35GW			Spring/Autumn 40GW			Winter 45GW			Winter 50GW			Winter 55GW		
		High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind
Demand		20	20	20	25	25	25	30	30	30	35	35	35	40	40	40	45	45	45	50	50	50	55	55	55
Additional Demand (ie Pumping)		2	2	2	2	2	2																		
Total Demand		22	22	22	27	27	27	30	30	30	35	35	35	40	40	40	45	45	45	50	50	50	55	55	55
Generation																									
"Must Run" generation																									
Baseload Synchronous	*11.8*	6.7	6.7	6.7	6.7	6.7	6.7	7.6	7.6	7.6	8.2	8.2	8.2	8.7	8.7	8.7	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Wind	*26.8*	16.1	8.0	.0	16.1	8.0	.0	20.1	9.4	1.3	20.1	9.4	1.3	20.1	9.4	1.3	24.1	10.7	1.3	24.1	10.7	1.3	24.1	10.7	1.3
Total "Must Run"	*38.6*	22.8	14.8	6.7	22.8	14.8	6.7	27.7	17.0	8.9	28.2	17.5	9.5	28.8	18.1	10.1	34.2	20.8	11.5	34.2	20.8	11.5	34.2	20.8	11.5
Total Generation Capacity	*100.0*																								
Primary Response																									
Requirement		2.9	2.4	2.0	2.2	1.8	1.5	2.1	1.8	1.4	1.8	1.4	1.2	1.4	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8
Static Response		0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Net Response Req		2.6	2.2	1.8	2.0	1.6	1.3	1.9	1.6	1.2	1.6	1.2	1.0	1.2	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6
Response on Synchronous Plant		0.5	1.5	1.8	1.0	1.6	1.3	0.8	1.6	1.2	1.1	1.2	1.0	1.2	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6
Response on Asynchronous Plant		2.0	0.8	0.0	1.0	0.0	0.0	1.2	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Response on Synchronous Plant																									
Assumed Loading Point		75%	75%	75%	75%	75%	85%	75%	75%	85%	75%	85%	85%	75%	85%	85%	75%	85%	85%	85%	85%	85%	85%	85%	85%
Assumed Deload/Response Ratio		50%	50%	50%	50%	50%	55%	50%	50%	55%	50%	55%	55%	50%	55%	55%	50%	55%	55%	55%	55%	55%	55%	55%	55%
Responsive Plant Deload		1.1	2.9	3.6	2.0	3.2	2.4	1.5	3.2	2.2	2.2	2.2	1.7	2.4	1.6	1.6	1.7	1.4	1.4	1.2	1.2	1.2	1.0	1.0	1.0
Power Output on Responsive Plant		3.2	8.7	10.8	6.0	9.6	13.5	4.5	9.6	12.4	6.6	12.4	9.8	7.2	8.8	8.8	5.1	7.8	7.8	6.7	6.7	6.7	5.7	5.7	5.7
Response on Asynchronous Plant																									
Assumed Loading Point		75%	75%	85%	85%	85%	85%	75%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Assumed Deload/Response Ratio		50%	50%	55%	55%	55%	55%	50%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
Responsive Plant Deload		4.0	1.5	0.0	1.7	0.0	0.0	2.3	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Output on Responsive Plant		12.1	4.5	0.0	9.8	0.0	0.0	6.9	0.0	0.0	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additional Balancing (Pullback)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Output on Non-responsive Plant		0.0	2.0	0.0	4.5	8.0	0.0	10.9	9.4	1.3	14.0	9.4	1.3	20.1	9.4	1.3	24.1	10.7	1.3	24.1	10.7	1.3	24.1	10.7	1.3
Aggregate Response																									
Power Output on Responsive Plant		15.3	13.2	10.8	15.8	9.6	13.5	11.4	9.6	12.4	11.8	12.4	9.8	7.2	8.8	8.8	5.1	7.8	7.8	6.7	6.7	6.7	5.7	5.7	5.7
Responsive Plant Deload		5.1	4.4	3.6	3.7	3.2	2.4	3.8	3.2	2.2	3.1	2.2	1.7	2.4	1.6	1.6	1.7	1.4	1.4	1.2	1.2	1.2	1.0	1.0	1.0
Additional Output Reqd		0.0	0.0	4.5	-0.1	2.6	6.8	0.1	3.4	8.6	1.1	5.0	15.7	4.0	13.1	21.1	5.7	16.4	25.8	9.1	22.4	31.8	15.1	28.5	37.8
Additional Balancing (Pullback)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generation		**22.0**	**22.0**	**22.0**	**27.1**	**27.0**	**27.0**	**30.0**	**30.0**	**30.0**	**35.0**	**35.0**	**35.0**	**40.0**	**40.0**	**40.0**	**45.0**	**45.0**	**45.0**	**50.0**	**50.0**	**50.0**	**55.0**	**55.0**	**55.0**

	Low Demand 20GW			Low Demand 25GW			Median Demand 30GW			Median Demand 35GW			Median Demand 40GW			High Demand 45GW			High Demand 50GW			High Demand 55GW		
	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind	High Wind	Average Wind	Low Wind
Nuclear	60%	60%	60%	60%	60%	60%	65%	65%	65%	70%	70%	70%	75%	75%	75%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Wind	60%	30%	0%	60%	30%	0%	75%	35%	5%	75%	35%	5%	75%	35%	5%	90%	40%	5%	90%	40%	5%	90%	40%	5%
CCS	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Other	75%	75%	75%	75%	75%	75%	80%	80%	80%	80%	80%	80%	80%	80%	80%	90%	90%	90%	90%	90%	90%	90%	90%	90%

Annex 7 - Draft legal text for Fast Frequency Response

1.0 General

1.1 The proposals below set out the very high level principles in addressing the need for a Fast Frequency Response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency.

1.2 For illustrative purposes only, the proposals have been drafted in the style of a Grid Code change. It is envisaged that the major changes would relate to the Glossary and Definitions, CC.6.3.7 and CC.A.3.

2.0 High Level Proposals for Primary Response

2.1 In order to limit the Rate of Change of Frequency following a generation loss or load change, each Generating Unit, Power Park Module (including Power Park Units thereof) or DC Converters which are insensitive to changes in system frequency and do not inherently contribute to system inertia shall be required to provide a Fast Primary Frequency Capability in addition to the requirements of CC.6.3.7 and CC.A.3.

2.2 A Fast Primary Frequency Capability shall be defined as:-

> "Primary Frequency Capability where the 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 – 5 seconds from the time of the start of the frequency fall (allowing for a maximum 1 second delay) on the basis set out in the Ancillary Services Agreement and fully available by the latter and sustainable for at least a further 25 seconds. The interpretation of Fast Primary Frequency Response to a -0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.4.

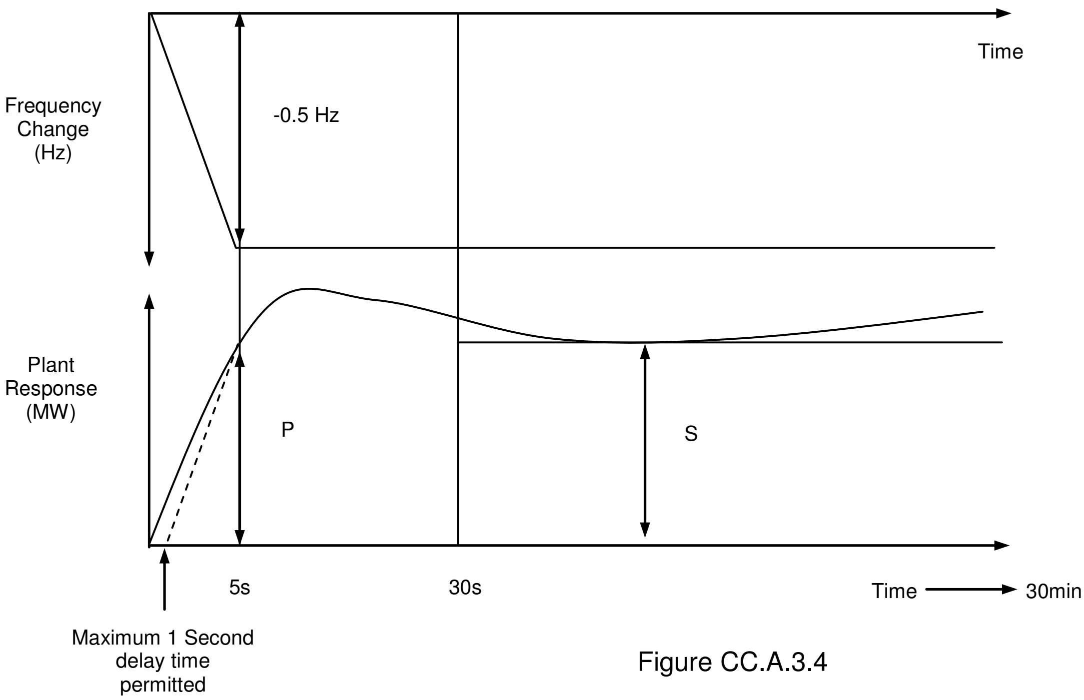


Figure CC.A.3.4

3.0 High Level Proposals for High Frequency Response

3.1 In order to limit the Rate of Change of Frequency following a demand loss or load change, each Generating Unit, Power Park Module (including Power Park Units thereof) or DC Converters which are insensitive to changes in system frequency and do not inherently contribute to system inertia shall be required to provide a Fast High Frequency Response Capability in addition to the requirements of CC.6.3.7 and CC.A.3.

3.2 A Fast High Frequency Response Capability shall be defined as:

> "High Frequency Response where the reduction in Active Power output in response to an increase in System Frequency above the Target Frequency (or such other level 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 – 5 seconds from the time of the start of the frequency increase (allowing for a maximum 1 second delay) on the basis set out in the Ancillary Services Agreement and fully achieved within 5 seconds of the time of the start of the Frequency increase and it must be sustained at no lesser reduction thereafter. The interpretation of Fast High Frequency Response to a +0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.5".

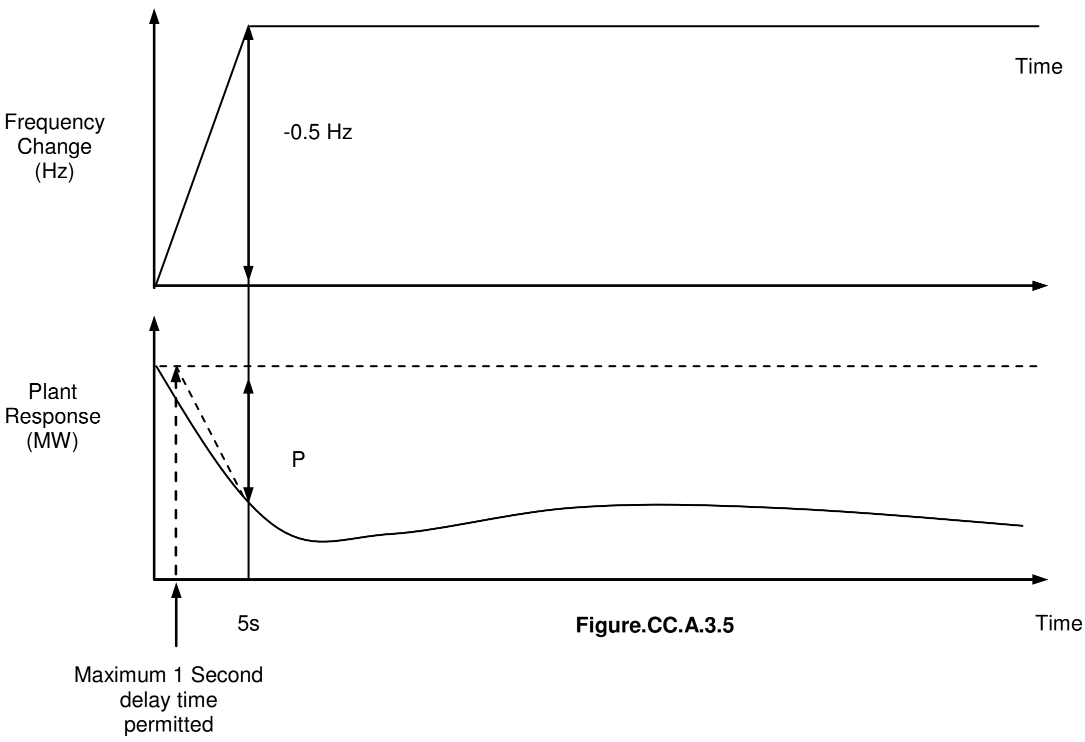


Figure.CC.A.3.5