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.

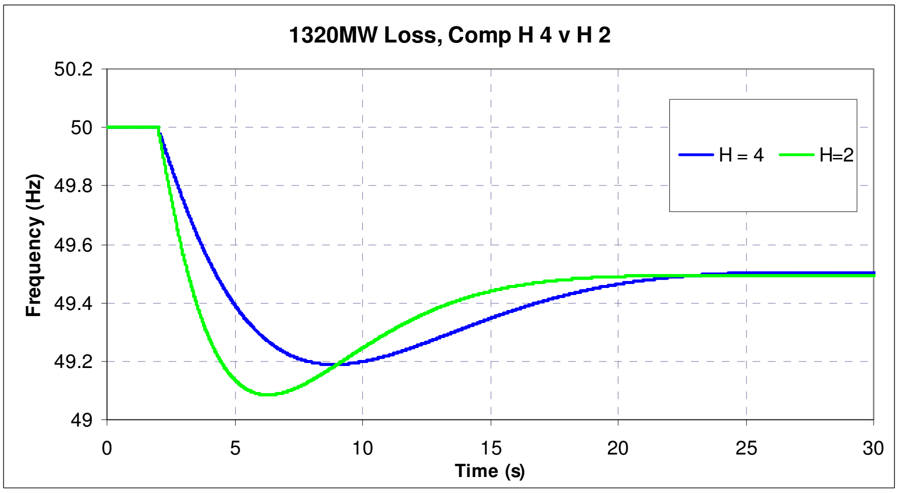

Figure 1.0

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

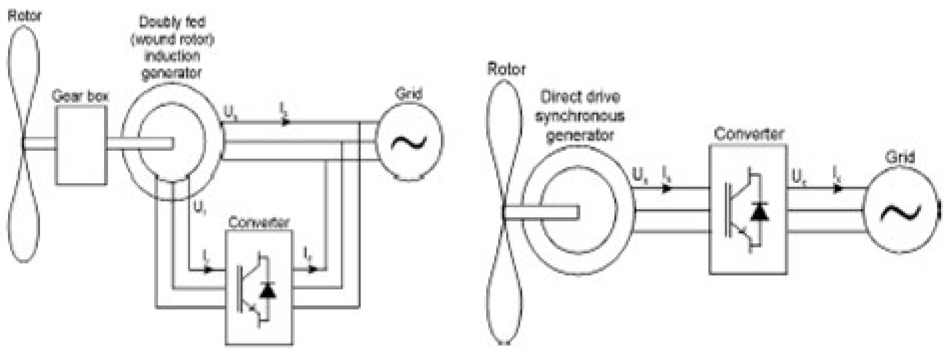

Figure 1.0A

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.

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

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

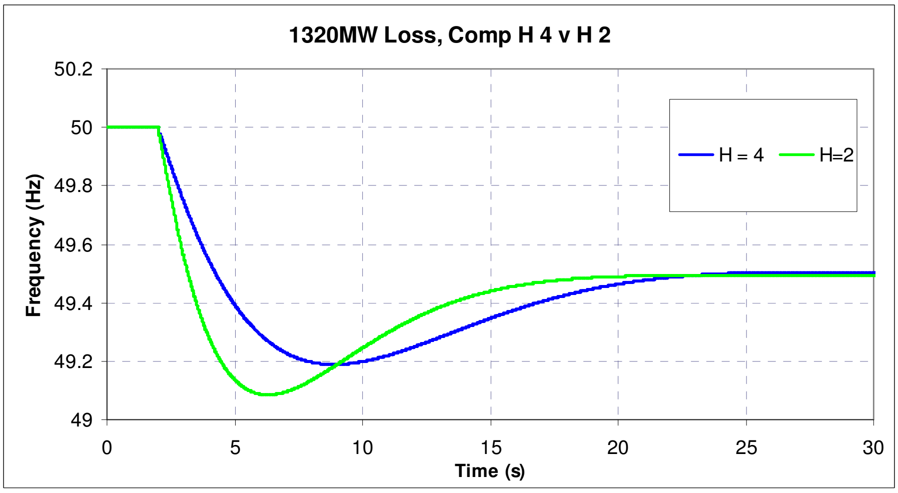

Figure 2.0A

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

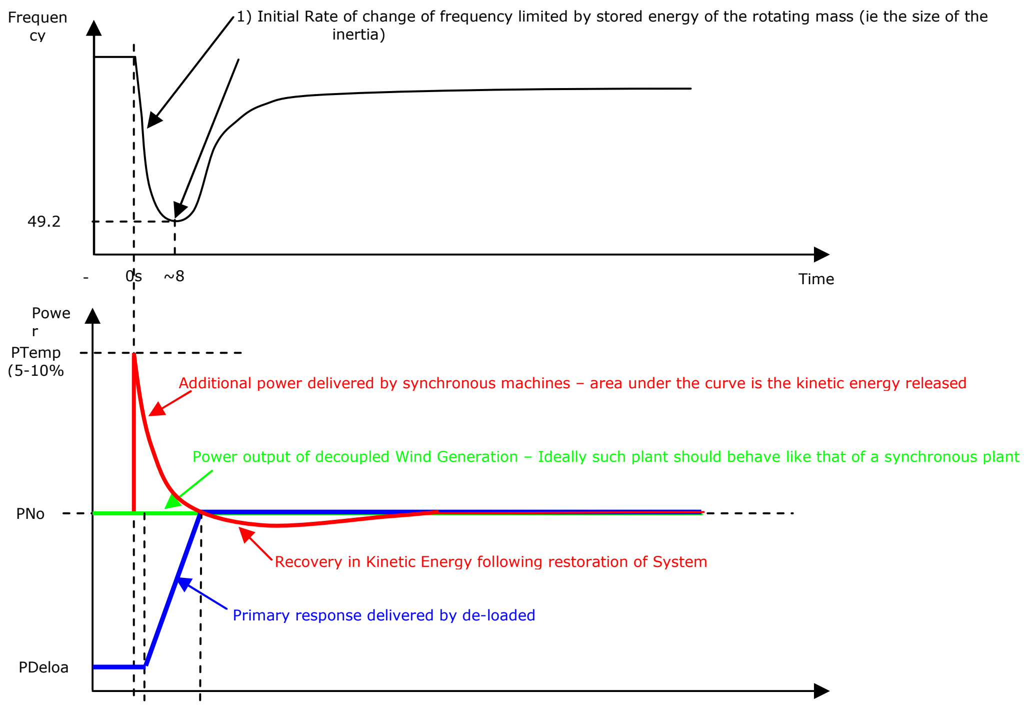

Figure 3.0A

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.

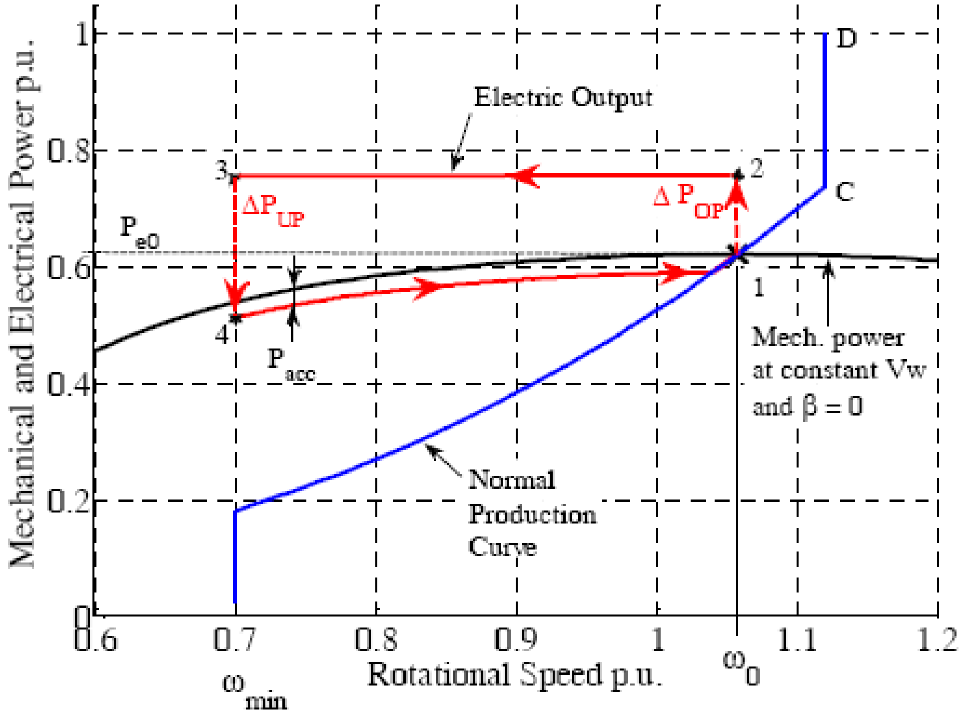

Fig. 3. WT power vs. rotational speed. The blue line is the WT normal (static) production power. The black line is the blade's mechanical power for a constant wind speed. The red line is the electric power set point for over-production process.

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.

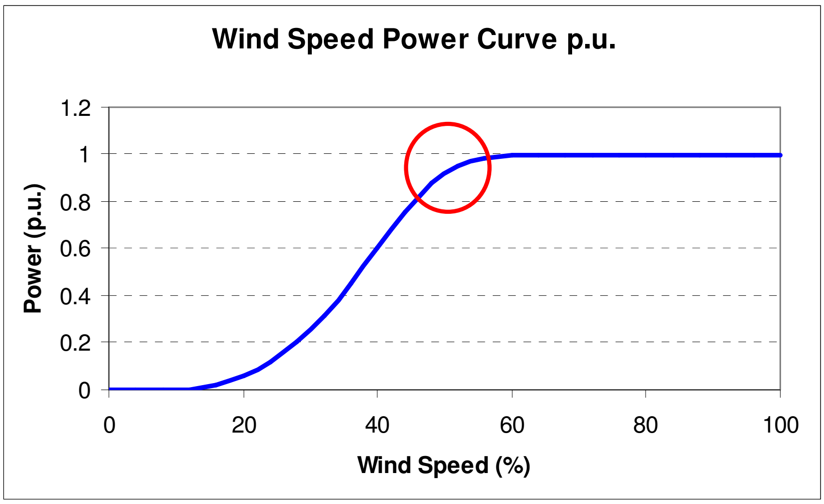

Figure 5.0A – Critical Wind Speed Recovery Period

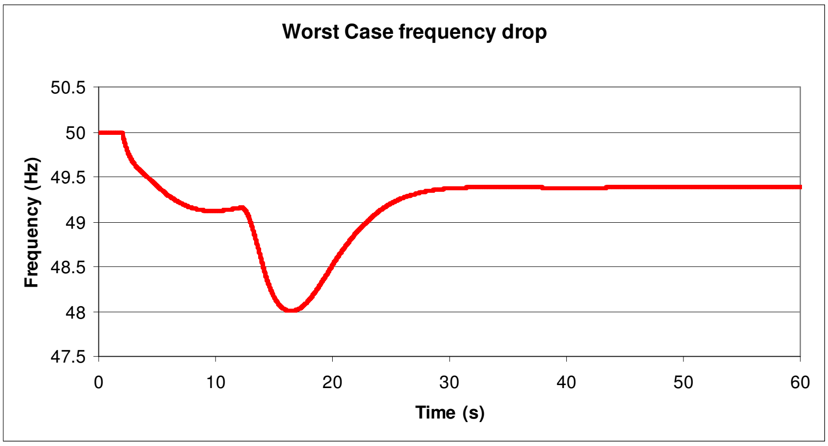

Figure 6.0A – Effect on System Frequency as a result of the Recovery Period at Critical Wind Speeds

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.

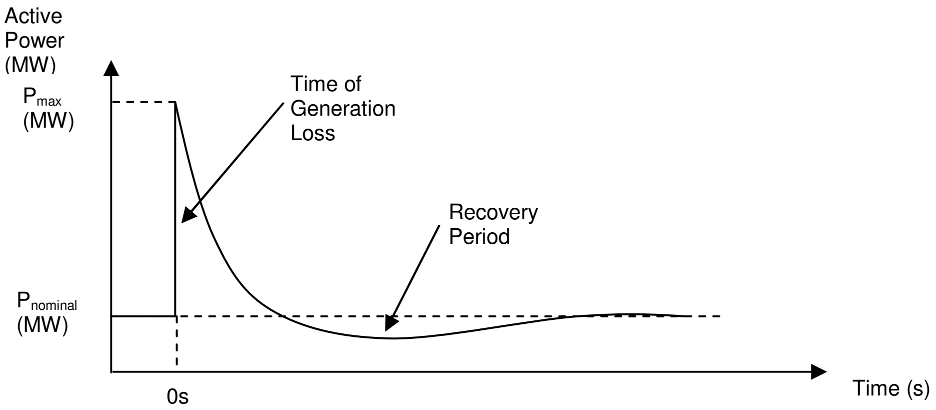

Figure 1.0B

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.

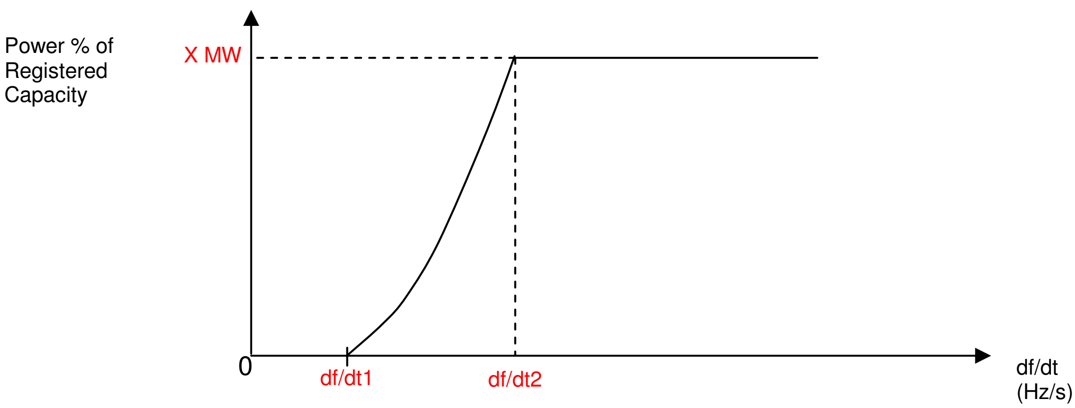

Figure 2.0B

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