NATIONAL GRID COMPANY plc

Background Information to Grid Code Consultation Document D/03

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"Grid Code Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions)"

Introduction

1. This paper has been written to provide additional background information on the Grid Code changes that are subject to the formal Grid Code consultation process under Consultation Document D/03. The Consultation Document D/03 proposes revision of the Grid Code to clarify the obligations on Generators utilising technology other than synchronous machines and on operators of DC Converter Stations.

2. With the changes in Government energy strategy to increase the proportion of electricity generated from renewable sources, the number of power stations using generation technology other than synchronous machines is set to increase dramatically. Early discussions between National Grid and potential developers of new generation (mainly wind farms), indicated that there was a lack of clarity in the Grid Code on the requirements that new plant employing non-synchronous generation technologies were obliged to meet and some doubt on the technical capabilities of some of the emerging technologies.

3. The proposed changes were developed by National Grid in discussion with interested parties sitting on the Grid Code Generic Provisions Working Group. The proposed changes to the Grid Code were discussed at the Grid Code Review Panel meeting held on 22nd May 2003.

The Development Process

4. The Generic Provisions Working Group included representatives nominated by Generators, Transmission Operators, Distribution Network Operators, British Wind Energy Association (BWEA) and wind farm developers. Also Ofgem was present as an observer.

5. Although wind turbine manufactures were not present on the group, National Grid discussed wind turbine present and developing technical capabilities with five large European manufacturers namely NEG Micon, Bonus Energy, Vestas, Enercon and GE Wind. To meet the manufacturers concerns on commercially sensitive information, National Grid was obliged to agree confidentiality terms with these companies.

6. The Grid Code Generic Provisions Working Group was established following the acceptance of paper GCRP 02/21 at the 5 September 2002 meeting of the Grid Code Review Panel. This paper recommended that the Working Group would propose revisions to the Grid Code to clarify the Connection Conditions in relation to the requirements on new generation technologies and modify other sections of the Grid Code to ensure continued clarity and consistency. Paper GCRP 02/21 asked the Working Group to take into account the recommendations of the HVDC Working Group as reported to the Grid Code Review Panel in paper 02/31 tabled at the November 2002 GCRP meeting, which relate to new HVDC Interconnectors.

7. The high level principles followed by National Grid and the Generic Provisions Working Group in developing the Grid Code change proposals were:-

   (a) Maintain transmission system security, stability and quality of supply,
   (b) Avoid undue discrimination between Users and classes of Users taking due regard of the economic impact of requirements,
   (c) Phase in the requirements to allow the generation technology to continue to develop and mature consistent with transmission system security needs,
   (d) Involve input from all stakeholders including Generators, the BWEA, wind farm developers, DNOs, and other transmission operators,
   (e) Be aware of existing technical requirements of overseas utilities and their relevance to the England and Wales technical context,
   (f) Ensure that the requirements help to facilitate the growth in renewable generation technologies in the medium and long term in line with the Government target,
   (g) Ensure that the requirements are transparent and clear and attempt to minimise Grid Code wording changes as far as practically as possible,
   (h) Specify requirements functionally at the connection point, where possible, in order to maximise the Generators flexibility in choosing how to meet the requirements.

8. The Working Group reported back to the Grid Code Review Panel at the 22 May 2003 meeting proposing detailed drafting changes for the Grid Code. The Grid Code Review Panel approved the issue of the proposals for formal consultation. The consultation document D/03 was issued on 6 June 2003 with the consultation period extended from the standard 4 weeks to a 6 week period. Further information on the work of the Generic Provisions Working Group including the minutes of meetings, terms of reference, a list of members and the final paper to the Grid Code Review Panel can be found on the website as follows: http://www.nationalgridinfo.co.uk/grid_code/mn_gpwg.html

Why Amend The Grid Code

9. National Grid has been in discussion with potential wind farm developers since the beginning of 2002 with regard to the application of the Grid Code to renewable generation sources. These discussions led to the conclusion that the Grid Code did not clearly identify the requirements on renewable generation and in a number of areas the inherent characteristics of synchronous generating plant was implicitly assumed.

10. Negotiations with developers applying for connection to the transmission system and views expressed by existing Generators also confirmed dissatisfaction with the approach of specifying requirements on a site by site basis through Bilateral Agreements. The major concerns were a lack of transparency in the requirements specified and the possibility of inequitable treatment between generation developments, both renewable technologies and traditional thermal plant.

11. The only way to bring clarity, consistency and equitable treatment is to identify the generic requirements explicitly for all renewable generation developments in the Grid Code. All potential developers and plant manufacturers then have open access to the requirements they will be expected to meet.

Timescale of the Grid Code Changes

12. National Grid believes that it is now the right time to bring forward the Grid Code change proposals to be applicable to renewable generation immediately following approval by Ofgem. The factors leading to this conclusion can be summarised as market penetration, transmission system security, generation technology development and the impact of delaying the introduction of requirements.

<u>Market Penetration</u>

13. Until recently the development of wind farms in England and Wales has been on a very small scale usually connected to the public electricity system at voltages below 132kV. The majority of individual farms have been less than 10MW in installed capacity. However the government energy policy is now encouraging the development of large scale renewable generation projects.

14. The first round of off-shore wind farms comprising 18 sites are each limited to a maximum of 30 turbines by the dti and developers are choosing capacities between 60 and 99 MW. The development programme published by the dti shows that the government is expecting these wind farms to start commissioning over 2004/2005. The total potential development is expected to be in the order of 1.6 GW by the year 2006.

15. For the second round of off-shore wind farms recent press releases from the government indicate that the dti has received applications for a total of 21 GW of off shore wind farm licences though some of which overlap the same sites. The development programme published by the dti shows that the government is expecting at least 4 GW of these wind farms to start commissioning in 2006. National Grid has, in fact, already received enquiries and applications for up to 5 GW of wind farms for connection to the transmission system from 2006.

16. The scale of this development should be considered in relation to the total system demand. Currently the typical overnight minimum summer demand is approximately 20 GW. In relation to this, it can be seen that wind farms have the potential to provide a large proportion of the required generation at such low demands. In the space of three years wind farms, as a sector of the generation market portfolio, will move from a minor provider to a significant part of the market.

17. This growth brings with it the requirement to have minimum technical capabilities and need to provide the services necessary to maintain security and quality of supply. The proposed Grid Code changes will form the basis of the technical requirements for the second round of off-shore wind farms. National Grid believes that this is an appropriate time to clarify the provisions of the Grid Code in relation to wind farm technology in particular.

<u>Transmission System Security</u>

18. Transmission system security relies on generating plant performing in accordance with the Grid Code and National Grid designing, planning and operating the network in accordance with the NGC Transmission System Security and Quality of Supply Standard (SQSS). With the current tiny

proportion of wind turbine generation spread across England and Wales in very small developments connected at low voltages, the technology does not have a material impact on transmission system security. The traditional large power stations that currently make up the bulk of the generation portfolio provide the services such as reactive power and frequency response necessary to operate the network.

19. In order to facilitate the growth in wind generation and ensure that barriers are not introduced in the face of local or overall developments, it is necessary that this technology can broadly provide similar levels of functional performance to existing generating plant. This includes some of the inherent characteristics of synchronous machines that are implicit in the Grid Code and the SQSS as well as the explicitly stated requirements.

20. The potential consequences of being unable to meet these requirements include :-
    - transmission system insecurity or an increase in overall system operating costs;
    - sterilisation of potential development sites in local areas, and hence restrictions on the development of renewable energy;
    - reduced quality in the electricity supplied to customers.

<u>Generation Technology Development</u>

21. As stated previously, National Grid had detailed technical discussions with five large European manufacturers namely NEG Micon, Bonus Energy, Vestas, Enercon and GE Wind.

22. The performance capabilities of the current wind turbine generator designs vary with the generator technology employed. While a few of the Grid Code Connection Conditions cannot be met by some of the existing technologies today, the issues tend to relate to specific types of machine from specific manufacturers. The direct liaison with manufacturers also showed that rapid progress was being made in the development and proving of those capabilities necessary to provide the services required in commercial products.

23. Overall, the Grid Code proposed changes apply to the whole wind farm at the connection point to the public network and do not specify technical requirements on a machine basis. This avoids favouring any particular type of machine technology and gives full flexibility to the designer in choosing how best the requirements are met.

24. In drafting the proposals and in recognition of the ongoing technical development, National Grid has delayed introduction of the full performance requirements until 1 January 2006 for provision of frequency response capability and reactive range capability.

<u>Impact of Delaying Introduction of Requirements</u>

25. National Grid believes that the Grid Code changes for new generation technologies should be applied at the earliest practical date after the full industry wide consultation including modifications introduced due to the consultation. Any delay would result in many round two off-shore wind farm developments being progressed on a case by case basis. This is a non-transparent process that is not acceptable to all industry parties. In addition

with the rapid growth in wind farm development, deferring the application date of the requirements further would give rise to the consequences discussed in paragraph 20 above.

Requirements of Other Utilities

26. In preparing the Grid Code change proposals, National Grid has been reviewing the requirements placed on renewable generation by other utilities in Europe. The proposed requirements for England and Wales are generally consistent with the requirements already introduced elsewhere in Europe whilst taking into account the technical characteristics of the island electrical power system of this country and cover the same issues identified by other utilities. A table comparing requirements in other countries and useful references to documents can be found in the attached appendices.

HVDC Interconnections

27. The development of the Grid Code to include specific provisions for High Voltage DC Interconnectors was given to the Grid Code HVDC Working Group of the England and Wales Grid Code Review Panel. The work of this group was reported in paper GCRP 02/31 at the November 2002 Grid Code Review Panel Meeting. The paper GCRP 02/31 concentrated on the changes required to the Planning Code, the Connection Conditions and Balancing Code 3 acknowledging that consequential changes would be required in other parts of the Grid Code.

28. The proposals discussed at the Generic Provisions Working Group adopted the majority of the drafting proposed and addressed the few remaining issues. The layout and formatting has however been altered to be consistent with the developments for non-synchronous generation technology. Consequential changes to incorporate DC Converters and DC Converter Station Owners have been made throughout the Grid Code.

Discussion of Major Technical Issues

29. The Generic Provisions Working Group explored a number of issues regarding the current and future capabilities of the new generation technologies. These issues are discussed in detail in the Appendices. Of these, Fault Ride Through, Stability & Loss of Power Infeed and Frequency Range remained requirements that some members of the working group were unable to endorse.

National Grid Company plc
6 June 2003

Appendix 1 – Comparison of Connection Requirements

Requirement	England and Wales	Scotland	Germany	Denmark	The Netherlands
			Document issue date 1 December 2001	Document issue date 26 April 2000.	Document issue date 29 October 2002
Power Factor Range	Unity Power Factor at the connection point to the public network. 0.95 lead – 0.95 lag at the Connection Point. *(After 1 January 2006)*	At generator terminals 0.96 lead – 0.98 lag *(now for <100 MW)* 0.95 lead – 0.9 lag *(now for > 100MW)* *(July 03 for <100 MW)* *0.95 lead to 0.85 Lag (Jan 2007 – all sizes)*	0.975 lead to 0.975 lag at the Connection Point *(From 1 Jan 2002)*	Reactive power neutral at the connection point.	0.8 lead - 0.85 Lag (assumed to be at the connection point)
Frequency Control	Limited Frequency Sensitive Operation Full frequency response capability required. *(After 1 January 2006)*	Capability to provide frequency response *(WF > 100 MW now)* *(WF 30 – 100 MW July 2004)* At frequencies above 50.5 Hz the output should reduce with a droop of 10%.	Limited Frequency Sensitive Operation. In excess of 50.25 HZ the plant must de-load with a droop of 40 %. *(From 1 Jan 2002)*	Frequency response capability required. Provision of frequency control under islanding conditions must be provided.	Contribution to primary frequency control, limited by the control strategy and wind conditions

Requirement	England and Wales	Scotland	Germany	Denmark	The Netherlands
Fault Ride Through	The wind farm should remain connected for a solid 3 phase fault on 400 and 275kV transmission system. No loss of power infeed.	Transmission system faults (ie 132 kV and above) for volt drops to:- *0% - July 2005 (<30MW)* *Jan 2004 (>30MW)* *15% -Jan 2004 (<30MW)* *Now (>30MW)*	Wind farm must remain connected down to 15 % voltage at the HV connection point for at least 680ms *(From 1 Jan 2002)*	Wind farm to remain connected for a 3 phase fault clearance and a two phase fault with unsuccessful re-closing.	The wind farm should not be disconnected for Grid voltages down to 0 % for 100 ms. 200 ms period of transient voltage recovery.
Frequency Range	47.5-52Hz Continuous 47-47.5Hz for 20 seconds	47.5-52Hz Continuous 47-47.5Hz for 20 seconds	47.5-51.5Hz Continuous *(From 1 Jan 2002)*	47-47.5Hz for 10 seconds 47.5- 48Hz for 5 minutes 48 - 49Hz 25 minutes 49 - 50.3Hz Continuous 50.3 - 51Hz 1 minute Above 53.0Hz disconnect	48 - 51Hz Continuous

Note
This table has been prepared by National Grid as a comparison summary interpreting the published requirements of other utilities.

Appendix 2 – References

Useful Documents on the Requirements of Other Utilities

1. Specifications for Connecting Wind Farms to the Transmission Network - Second Edition - Eltra - Transmission System Planning - 26 April 2000, Document Number 74557. (Denmark)

2. "E.ON Netz - Supplementary Grid Connection Rules for Wind Energy Plants - Supplementary Technical and Organisational Regulations for Connecting Wind Energy Converters - Additional technical and organisational regulations for the Grid connection of wind energy converters within the regulatory zone of E.ON Netz GmGH". Dated – 11 December 2001
3. (Document translated from German to English by the order of ENERCON GmGH.)

4. NEG Micon - Electrical Grid Requirements Dowec - NM 6000 - Document Number R090-JBZ-R0107. Jan Brozelie Dated 29/10/02 [Note that this is a comparison of European Grid Code Requirements and includes the Netherlands, Germany, Denmark, Scotland and England / Wales by NEG Micon.]

5. Estonian Requirements "Technical Requirements for Connecting Wind Turbine Installations to the Power Network - Reference EE 10421629 ST 7:2001"

6. "Guidance Note for the Connection of Windfarms". Scottish Power Transmission and Distribution and Scottish Hydro Electric. Issue 2.1.4 dated 17 December 2002. Proposed Changes to the Scottish Grid Code.

Appendix 3 - Reactive Capability

Background

Voltage and reactive power control are required for the following reasons:
a) protect plant and equipment from damaging over voltages,
b) facilitate transfer of active power,
c) maintain adequate voltage quality at the point of connection to customers.
Unlike active power, reactive power cannot be transmitted efficiently across long distances and has to be supplied locally to meet the above three reasons.

While a synchronous machine has an inherent capability to provide a controlled reactive power output resulting from the need to ensure stable synchronous operation, the basic induction generator employed in many existing small size wind farms does not. An induction generator absorbs reactive power from the host network. Further, a wind farm may contain a considerable network that will have it's own reactive characteristics that will vary with loading. Where long cable lengths are present, the wind farm may naturally spill reactive power on to the host network.

The uncontrolled absorption of reactive power from the host network by a wind farm would have the effect of depressing system voltage in the local area of connection. Conversely the uncontrolled generation of reactive power by a wind farm would have the effect of raising local system voltage. In order to control voltage quality to customers, additional reactive support may then be needed from other generators or from dedicated reactive compensation plant assuming this is available in the area. National Grid believes that to maintain the quality of system voltage and avoid unfairness to other users of the transmission system, some reactive capability requirement should be placed on wind farm generators. This provides the opportunity to share in reactive market opportunities.

Method of Specification

Although including a minimum capability specification in the Bilateral Agreement on a site specific basis was considered, the Working Group considered that this was undesirable for the following reasons:
- not transparent to users
- could result in unequal treatment
- is difficult for a connecting Generator to assess potential requirement
- could result in a Generator having a very large reactive requirement in excess of the current Grid Code limits placed upon it, although this could be capped
- unclear division of reactive power capability provision responsibilities between Generator and Network Operator.

Including a clear generic minimum requirement in the Grid Code was seen to offer the following benefits:
- transparent to all system users
- ensures fair and equitable treatment
- limits the obligation on a generator to provide reactive power capability range
- provides a clear division in responsibility between network operator and generator to provide reactive power capability
- clear specification to developers.

<u>Proposals Considered</u>

A number of reactive capability proposals were considered by the Generic Provisions Working Group for inclusion in the Grid Code.

These can be summarised as:

Option 1 – Capability of +/- 0.92 power factor at the HV connection point. This is nominally equivalent to the current requirement for synchronous machines.

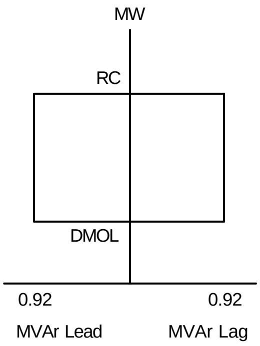
Option 2 – Capability of +/- 0.95 power factor at the HV connection point. This is similar to Option 1 but with the range reduced in line with Grid Code Reactive Power Working Group recommendations.

Option 3 – Capability of unity power factor. Based on the recommendations of the Grid Code HVDC Working Group and similar to the bare minimum operational requirements of the Grid Code Reactive Power Working Group.

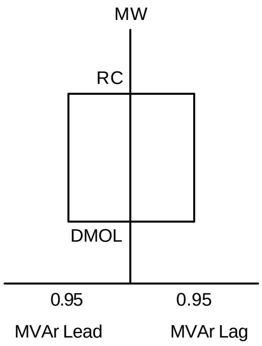
Option 4 – Capability at the connection point resulting from +/- 0.95 power factor at the individual unit LV terminals. The capability always includes unity power factor at the connection point.

The four options are illustrated below.

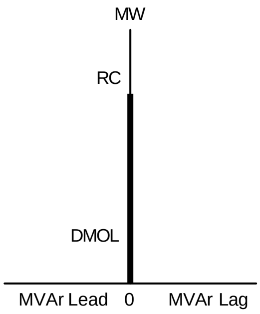
<u>Option 1</u>



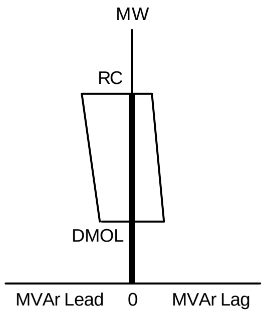
<u>Option 2</u>



<u>Option 3</u>



<u>Option 4</u>



The advantages and disadvantages of the four options are considered below

Option	Pros	Cons
1	Consistent with the current requirements for synchronous machines.	Difficult to justify as in excess of recommendations of the Grid Code Reactive Power Working Group.
	Positive long term signals to developers.	May need some thyristor control of reactive compensation if older generation of wind turbine generators used.
	Avoids long term issues on reactive power provision.	Maybe potentially costly on developers
2	Less cost implications for developers particularly if current generation of wind turbine technology used.	Inconsistent with the current requirements for synchronous machines.
	Consistent with bulk of manufacturers claim that they can provide at least this range at the individual machine terminals.	May need some thyristor control of reactive compensation if older generation of wind turbine generators used.
	Easier to meet for controllable equipment than option 1.	May be some issues on future reactive power provision for National Grid.

Option	Pros	Cons
3	Minimum demand on developers and therefore least developer cost.	Potential for major implications on long term procurement of reactive power by the transmission operator.
	Suitable for older generation of non-synchronous generation technology.	Potential cost penalties on transmission operation.
	Consistent with bare minimum operational recommendations of the Reactive Power Working Group.	Operational difficulties for control of transmission system voltage.
4	Development of Option 3.	The lead & lag reactive capability not known to National Grid at the application stage.
	Simple specification for developer and manufacturer.	Range eventually made available may not be of practical use to network operator.
	Capability incorporated at machine terminals may give better dynamic performance	Less useable capability than options 1 & 2.
	May provide some consequential capability at the Connection Point based on machine capability.	Appears to be designed around a specific existing generator type so potential disadvantages to some manufacturers or developers using other technology.

Having considered these four options, National Grid has proposed a development of the Grid Code based on Options 2 and 3. The reactive capability proposals (see Grid Code CC6.3.2) have been drafted to reflect both the needs of the transmission system in terms of security and quality of supply and the need to allow the continued development of the new technologies to provide improved capability. To allow time for this and to provide an appropriate signal of the transmission system requirements in the longer term, a staged introduction of the requirements is proposed. This can be summarised as:

> Wind farms, non-synchronous generating units and DC converters with completion dates prior to 1 January 2006 would be required, as a minimum, to be capable of operating to an instruction for zero MVAr transfer at the connection point i.e. operation at unity power factor. To ease this requirement further, a tolerance around the dispatch instruction would be acceptable and this would be specified at the connection offer stage in the Bilateral Agreement.
>
> Wind farms, non-synchronous generating units and voltage-source DC converters with completion dates on or after 1 January 2006 would be required to have a symmetrical reactive power capability between a leading and lagging power factor of 0.95 at the connection point (Option 2). This is in line with the Reactive Power Working Group's recommendations.

The decision not to increase the reactive capability requirement on conventional current-source DC converter technology is based on the following:

- compared to wind farms, the expected future market penetration is very low. No current-source DC converter station has connected to the NGC transmission system since 1986 and only one such DC converter station has a commitment for connection.
- DC converter stations utilising developing voltage-source technology are capable of reactive power regulation in a similar manner to most wind farm technologies.

Appendix 4 – Frequency Range

The National Grid transmission system operates to a nominal frequency of 50Hz by balancing generation and demand continuously on a second by second basis. System frequency is uniform across the total electricity system in Great Britain and at privatisation the obligation to control system frequency was placed on NGC.

NGC is required to control the system frequency within the statutory range of 49.5Hz to 50.5Hz under normal system operating conditions. However to ensure continued transmission network security under abnormal operating conditions, the Grid Code specifies that all generating plant should also be able to operate,(i.e. not to be disconnected) between a wider frequency range of 47Hz to 52Hz.

This requirement is tied to the national transmission system frequency defence plan where low frequency demand disconnection relays are provided as an emergency network security protection and resilience plan against a full or partial system blackout situation. Therefore, it is very important that wind farms are not disconnected down to 47Hz otherwise the number of consumers whose supply would be disconnected would be increased, leading in the worst case, to a total system blackout situation.

The discrete nature of the operation of the national transmission system frequency defence plan can in turn cause system frequency to overshoot and rise transiently to 52Hz. Therefore, it is very important that wind farms are not disconnected up to 52Hz otherwise the number of consumers whose supply would be disconnected would be increased leading, in the worst case, to a total system blackout situation.

Under the Grid Code, all generation projects above 50MW, irrespective of type, that connect to the transmission or distribution networks, are required not to be disconnected over this 47Hz to 52Hz frequency range. Although a slight relaxation from the upper frequency range in initial individual cases, where evidence from developers showing the plant not to have the full capability might be judged as acceptable, substantial relaxation would increase the risk of additional customer demand disconnection and extent of blackout.

Appendix 5 – Frequency Response

Background

One of the principal requirements of the Electricity Safety, Quality and Continuity Regulations 2002 is that there should not be a permanent change in system frequency outside the statutory limits of 50 Hz +/- 0.5Hz in the event of any of the contingencies defined in the licence standards occurring.

In order to achieve this, a frequency response service is required from generating plant. Generating plant providing this service is required to vary active power output in response to changes in system frequency. Because electricity cannot be stored in sufficient quantities, supply and demand have to be balanced instantaneously so automatic frequency control is necessary.

Under the Grid Code, all Power Stations with an installed capacity of 50MW or more are required to be capable of providing frequency response. Some nuclear generation designed and built before 1990 was exempted on design safety grounds from frequency response provision but not from limited frequency sensitive operation.

Wind Farm Frequency Response Capability

Historically generating units within wind farms have been simple induction generators with little control over the power extracted from the wind (commonly referred to as passive stall turbines). However, in recent years to improve efficiency, developments have taken place allowing turbines to control the power extracted (commonly known as active stall or variable speed pitch controlled turbines). Therefore this generation technology has a latent capability to providing frequency response by controlling the electrical power output in relation to the maximum energy that can be extracted from the wind.

Overseas utilities have already begun specifying a requirement for a frequency response capability. Published material from recently commissioned international wind farms such as Horns Rev have demonstrated that wind farms can be designed and operated to provide a “balancing” service to the transmission operator. Discussions over the last year between National Grid and a cross section of European manufacturers indicate that the frequency response technology should currently be considered as developmental. However all the manufacturers have reasonable expectations of marketing a commercial product with a full frequency response capability early in 2004. Therefore developers placing orders for wind farms in 2004 for commissioning 12 to 18 months later should be able to provide full frequency response.

Wind Farm Market Penetration

The first phase of off-shore wind farms comprising 18 sites are each limited to a maximum of 30 turbines by the dti and developers are choosing capacities between 60 and 99 MW. It is expected that these developments will not be required to have a generation licence, thereby relieving them from complying with the requirements of the Grid Code. The development programme published by the dti shows that the government is expecting these wind farms to start commissioning over 2004/2005. The total potential development is expected to be around 1.6 GW by 2006.

For the second phase of off-shore wind farms recent press releases from the government indicate that the dti has received applications for a total of 21 GW of off-shore wind farm licences. The development programme published by the dti shows that the government is expecting at least 4 GW of these wind farms to start commissioning in 2006.

The scale of this development should be considered in relation to the total system demand. Currently the typical overnight minimum summer demand is approximately 20 GW. In relation to this, it can be seen that wind farms have the potential to provide a large proportion of this generation. Given the clean nature of this generation it would seem illogical for it to be displaced with less environmentally friendly (fossil fuelled) generation in order to provide the necessary frequency control to enable NGC to continue to manage system frequency performance securely.

Proposed Requirements on Wind Farms

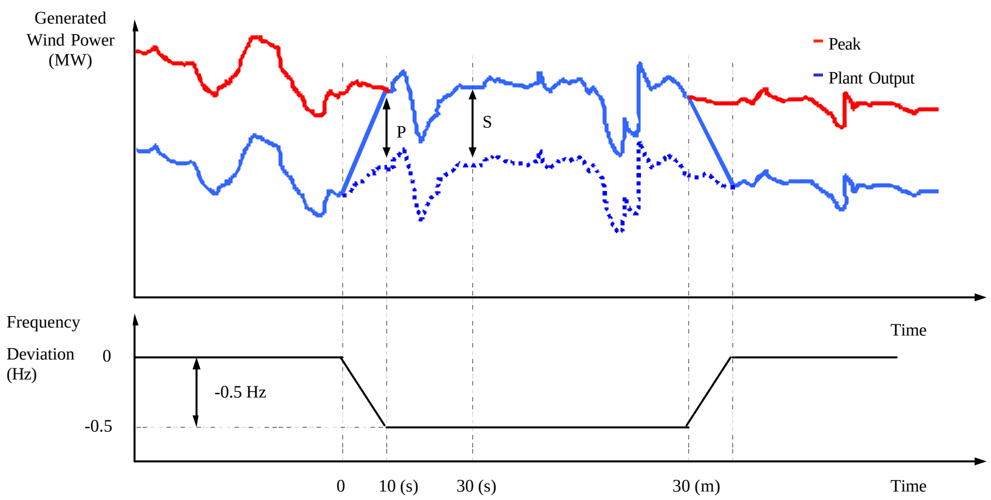
National Grid believes that it is reasonable to require the new generation technologies with completion dates on or after 1st January 2006 to provide a full frequency response capability. This view takes into account the following:

- the current state of wind farm technology and the lead times in project development
- the potential future market penetration of wind farms
- the need to maintain frequency control and system security in the future
- to minimise operation of less environmentally friendly generation
- to allow frequency response levels to be maintained independent of plant mix.

New generation technologies commissioning before the 1st January 2006 will be required to be capable of limited frequency sensitive operation. Essentially this requires generators to be capable of reducing active power by at least 2 percent of output per 0.1Hz deviation of system frequency above 50.4 Hz. This can be delivered from wind farms either by controlling the power output from individual wind turbines or by reducing the number of wind turbines generating within the wind farm.

Discussion of frequency response delivery

National Grid understands that active power from a wind farm will vary with wind speed, however this is not a bar to providing frequency response. In the following figure the top red line indicates the power that could potentially be exported by a wind farm extracting maximum power from the wind energy. The lower blue line indicates initial part loading of the wind farm and shows that when system frequency falls the power output from the wind farm rises to its theoretical maximum and falls again as system frequency recovers.



Assessment of the delivery of the frequency response service from a wind farm will require the variation in available energy at a site to be monitored in addition to active power output. From this data, the performance can be checked using an agreed power / wind speed curve for the site.

One area of discussion at the Working Group was the variability in wind speed within any individual site and the effect this would have on the holding of frequency response provision. This was raised from information tabled for a small five-turbine wind farm. While an issue if only one wind farm was providing response, National Grid would expect a number of wind farms at geographically diverse locations to be providing frequency response to smooth out sudden losses in response due to local wind speed changes, thereby maintaining an acceptable level of overall frequency control service. In addition, in the Balancing Market, the Generator would be submitting Maximum Export Limits and Physical Notifications for each half hour settlement period based on forecasts of wind speed giving some expectation of output level.

Cost of Lost Energy Production

Concern was expressed at the Generic Provisions Working Group that requiring wind farms to reduce output in order to provide frequency response would not be economic given the perceived low production costs.

With self-dispatch under NETA, the output level is declared by the Generator. If National Grid requires plant to operate at a higher or lower level in order to provide frequency response, the change in output is instructed by accepting the bid or offer at the balancing market energy price declared by the generator. This market mechanism ensures that the economics of renewable energy production are reflected in the scheduling of frequency response.

Appendix 6 – Fault Ride Through, Stability and Loss of Power Infeed

Introduction

The NGC Security and Quality of Supply Standard includes criteria for the connection of a power station which have particular relevance here. Following a secured Fault Outage, there shall not be :

i) Insufficient Voltage Performance Margins
ii) System Instability
iii) Any Loss of Power Infeed.
Note: The above terms are defined in the NGC Security and Quality of Supply Standard

In general, the inherent characteristics of synchronous machines are such that these requirements are rarely an issue and therefore no specific, explicit requirements are deemed to be necessary in the Grid Code. However, for other types of technology where the response to a Fault Outage is less clear, it is important to ensure that the requirements in the SQSS continue to be satisfied, particularly those identified above.

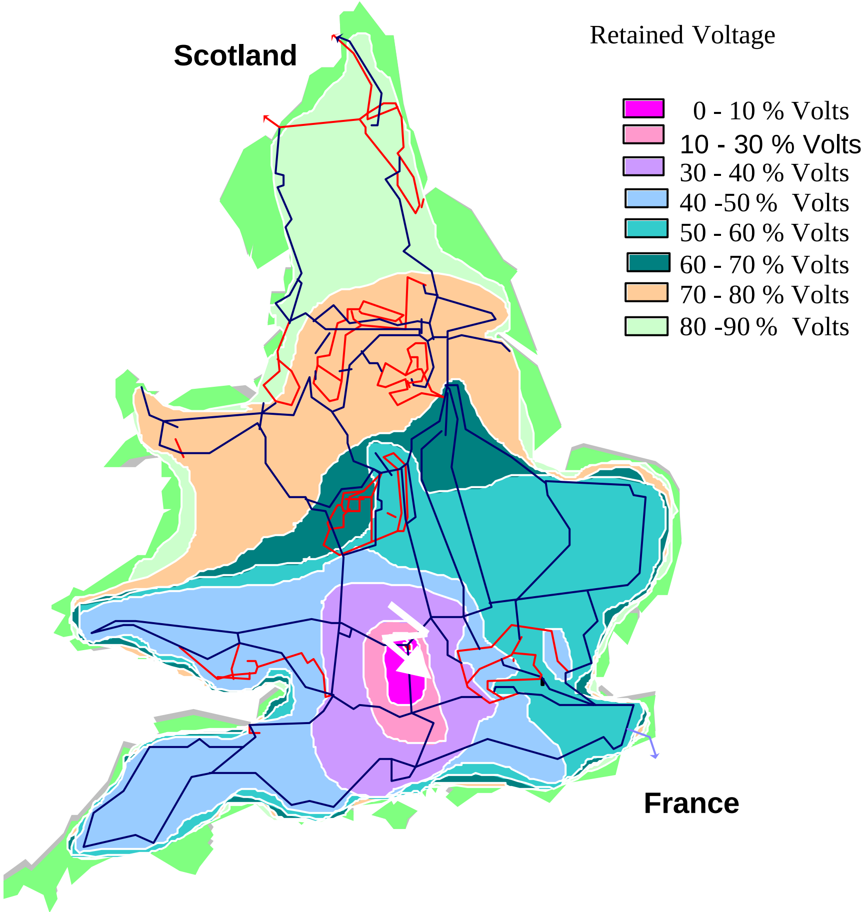
Fault Ride Through

Under the NGC Security and Quality of Supply Standard referenced from the Transmission Licence, the National Grid Transmission System is designed, planned and operated so that the maximum loss of generation for a secured event will not exceed 1320MW. The system is therefore designed and operated so that any credible fault (and subsequent switching out of transmission system plant to clear the fault) will not cause the disconnection of more than 1320MW of generation. Should a loss of generation occur exceeding 1320MW, the fall in system frequency is likely to cause widespread customer demand disconnection by the national network low frequency defence plan. Since a fault may cause large system voltage depression down to as low as zero at the point of the fault, any neighbouring generation will see a short term reduction in voltage which is dependent on the proximity of the fault.

Traditional "synchronous" generating units are inherently capable of continuing to operate through the transient voltage depression that accompanies any system fault event. Therefore a fault on a generating unit or its connections will not cause the loss of any other generating unit outside the fault clearance zone. The transmission system is designed and operated on this basis.

For clarity, the requirement to withstand faults on the transmission system has been added to the Grid Code. Without this ability there will either be a significant increase in the risk of customer disconnection spread across the whole country following a single fault, or there will be severe restrictions on the future concentrations of wind farm development in local areas.

This is illustrated by the figure below where the voltage across the system during a 3 phase fault applied at Cowley 400 kV substation is shown. It can be seen that all substations in England and Wales are temporarily exposed to levels of less than 90 % of nominal voltage. The area where transmission system voltages are depressed below 10% covers a large part of Oxfordshire despite the presence of a large synchronous generator connected to the adjacent substation.



Some wind turbine technologies are reported to be susceptible to tripping even if the voltage transiently falls to levels as high as 70 %. The outcome of this would be significant volumes of generation would be lost. In this example all wind farms in the South of England and Wales would disconnect.

In order to relax and ease this requirement as far as practicable, fault ride-through capability is only required for faults on the 400/275 kV transmission system because of the wide propagation of the voltage disturbance. For faults at 132 kV and lower voltages the impedance of the supergrid transformers limits the severe transient voltage depression across the transmission network. However the voltage on the distribution system will be depressed. Current expectations are that it is unlikely that very large amounts of wind farm generation (exceeding 1320MW) can practically be connected within such a 132kV distribution group. From the transmission operators point of view, fault ride through capability for distribution faults should not be an issue because the simultaneous loss of large amounts of centrally connected generation would be very unlikely to be beyond the credible loss limit of 1320 MW.

<u>The Disconnection Option</u>

As discussed, several wind farm technologies are reported to be susceptible to tripping in the event of a remote fault. The option of disconnecting wind farm generators during a fault condition and reconnecting after the fault was cleared has been considered. Whilst this might avoid a ‘permanent’ trip due to the fault, liaison with manufacturers and developers indicates that the duration of disconnection would be in the order of 5-10 seconds.

An analysis has been carried out into the impact of disconnecting wind farms following a fault coincident with a 1320MW generation loss and instantaneously reconnecting the wind farms at full power output. The table below shows the additional fall in transient frequency caused by wind farms disconnecting.

Table showing additional frequency fall (Hz)				
	Wind Generation Disconnecting (MW)			
Wind Generation post fault disconnection time (s)	500	1000	2000	4000
2	0.118	0.336	0.928	1.948
5	0.437	0.965	2.147	4.659

When considering the results in the table it should be noted that there is only a 0.2 Hz margin between the lowest frequency for a secured generation loss and (first stage) disconnection of 5% of total national demand. It can clearly be seen that even a temporary additional loss of wind farm output for a short duration will impact on customer security.

While the disconnection and reconnection option may be acceptable on large interconnected overseas networks where the impact on system frequency would be small, National Grid does not believe that this option is acceptable on the England and Wales system.

<u>Loss of Power Infeed</u>

To avoid a loss of power infeed in practice requires the mechanical power during and immediately after a fault to be nominally constant. This is virtually the case for synchronous machines where the mechanical power slightly and reduces transiently through normal governor action as the speed transiently increases by a small amount. Similarly, if it were the case for induction machine technology that no deliberate control action in response to a fault to reduce mechanical power was taken during and immediately after the fault duration, it is apparent that no significant Loss of Power Infeed would occur. Obviously, a certain amount of natural or normal transient control action could occur for other purposes during the short time of the fault and immediately after. However, as with governor action for synchronous machines, this should be relatively small.

It was decided to include the specific requirement regarding no deliberate action to be taken to reduce prime mover mechanical power output as it is apparent that some wind-turbine manufacturers could consider doing so by fast pitch control to prevent over-speeding in some circumstances. In order to prevent a Loss of Power Infeed occurring, such control action would need to be inhibited for the relatively small speed deviation that would occur during a fault condition.

All of the above is relevant to non-synchronous generating units. However, for DC Converters, these can easily be designed to recover from faults very quickly both in terms of power and voltage but this may be too quick for the system in the vicinity. It would therefore seem reasonable that the fault recovery characteristics should be site specific and therefore defined in the Bilateral Agreement. The purpose of the site specific requirements is therefore to ensure the co-ordination of the converter recovery with the capabilities of the system by controlling the recovery characteristics. In practice, this will always mean slowing down recovery rates from what could actually be achieved and therefore should not impose any constraints on the converter design.

Conclusion

The consequences of not having fault ride through and maintenance of power infeed capability would result in one or more of the following:-

- increased risk of widespread customer disconnection.
- restriction on generation development in some geographic areas.
- substantial increase in balancing costs for holding additional frequency response, ultimately paid for by customers.

As described above, fault ride through and maintenance of power infeed has important implications for the security and economics of electricity supply in England and Wales. In view of this and the development of similar requirements by other utilities, National Grid believes these requirements to be reasonable, even though it is acknowledged that there may be technical issues associated in meeting this requirement for a particular type of non-synchronous generator technology.