THE NATIONAL GRID COMPANY plc

GRID CODE REVIEW PANEL

GRID CODE CHANGES TO INCORPORATE NEW GENERATION TECHNOLOGIES AND DC INTERCONNECTORS (GENERIC PROVISIONS)

SUMMARY

1. In October 2003, National Grid submitted a report to Ofgem entitled 'Grid Code Changes to Incorporate New Generation Technologies and DC Interconnectors (Generic Provisions)' proposing changes to the England & Wales Grid Code. Ofgem wrote to NGC on 6th November 2003 outlining that further development was required by all interested stakeholders. The Scottish transmission licensees made proposals to Ofgem regarding wind farms in December 2002. At present, both proposals have not yet been either formally accepted or rejected by Ofgem.

2. Since then, a significant amount of additional ongoing development work and discussions have taken place through a process initiated and managed by Ofgem in conjunction with the Scottish transmission licensees, Generators and wind farm developers including members of the Generic Provisions Working Group.

3. The development work and the associated discussions have led both the two Scottish transmission licensees and NGC to change, refine and converge some of their respective proposals. Two co-ordinated consultations will therefore be carried out by the GB transmission licensees in respect of revised proposals for each of the two Grid Codes: the Scottish Grid Code and the England & Wales Grid Code.

BACKGROUND TO THE FIRST CONSULTATION

4. Early in 2002, NGC recognised the growing importance of new wind turbine generation technologies on the England & Wales system and the potential large increase in the volume of connections of such generation technologies to the system. However, the existing England & Wales Grid Code provisions do not adequately cover non-synchronous wind turbine generator technologies. These factors made it necessary that specific provisions for such technologies are included in the Grid Code. The requirements for DC Interconnectors were drawn by a previous GCRP working group and were included in the Generic provisions Working Group at the September 2002 GCRP meeting. For further background on the consultation and the report to Ofgem, the reader is referred to paper reference GCRP 03/11 dated May 2003 and the NGC report to Ofgem dated 31 October 2003 which can be found on the NGC web site from the following link:

http://www.nationalgrid.com/uk/indinfo/grid_code/mn_consultation_papers.html

DEVELOPMENTS SINCE THE FIRST CONSULTATION

5. Following the submission of the NGC report to Ofgem on 31 October 2003, Ofgem publicly advised that they could proceed with the proposals in a number

of ways. These were: i) accept the proposals, ii) reject the proposals, iii) undertake a further process of consultation or iv) initiate further development work. In the event, Ofgem advised that option (iv) would be followed.

6. The scope of this further development work as advised by Ofgem had the following stages:

(a) Alignment of the Scottish and England & Wales Connection Conditions proposals where there are differences excluding those due to the two different market contexts.

(b) Further meetings/discussions between the GB transmission licensees and manufacturers in the presence of Ofgem to check the manufacturers latest machine technical capabilities as well as new developments undertaken in the preceding 12 months.

(c) Forums of key stakeholders including representatives from the transmission licensees, Generators, wind farm developers, trade associations, manufacturers and SKM (consultants appointed by Ofgem).

(d) Transmission licensees to consider the views raised at the above Forums and any appropriate updates to the proposals from the last submission to Ofgem and consult on the changes made.

(e) Transmission licensees to resubmit the final proposals to Ofgem.

7. In November and December 2003, the three transmission licensees identified a number of small differences between their proposals and changes were made to align them. This process was completed in January 2004 and resulted in a number of alterations in the Connection Conditions.

8. Following this alignment, the three transmission licensees and Ofgem met with a total of 8 wind turbine and 2 power electronic equipment manufacturers in the first quarter of 2004. Appendix 1 gives more information on these meetings.

9. Following the manufacturer meetings, Ofgem arranged two Forums or stakeholder meetings with the first taking place on 24th and 25th of March 2004 and the second on 30th April 2004. The official minutes from these meetings are produced by Ofgem and are available on their website.

10. The first meeting on 24th and 25th March involved presentations on the first day by several manufacturers, the transmission licensees and the developers. The second day consisted of discussions of the key areas between the parties including Ofgem and SKM. At the end of this meeting, it was agreed to hold a second meeting on 30th April 2004 to allow for further discussions and revisions.

SUMMARY OF THE CHANGES SINCE PREVIOUS PROPOSALS

11. The main changes since the 31st October 2003 proposals are changes to the Connection Conditions, a change to the Planning Code and the corresponding change to the Data Registration Code. In summary, the changes are:

(a) The inclusion of a dynamic model description requirement in the Planning Code and the corresponding change to the Data Registration Code.

(b) Changes to the Connection Conditions in the following areas:

(i) Reactive Power and Voltage Control
(ii) Frequency Control
(iii) Negative Phase Sequence
(iv) Fault Ride Through

<u>Reactive Power and Voltage Control</u>

12. A reactive capability diagram has been introduced over the full operating range down to the active power output level defined as the Designed Minimum Operating Level (DMOL). In addition, a tolerance around the zero MVAr level requirement between DMOL and zero active power output, where operation is at the discretion of the plant owner, has been specified. A diagram has also been added to illustrate the reduced requirement on embedded plant connected at 33kV or below in terms of generating reactive power at high system voltages and absorbing reactive power at low system voltages. Appendix 2 gives more information.

<u>Frequency Control</u>

13. The provision of primary, secondary and high frequency response capability is still required but will only be required to be operational from 1st January 2006. During the forum discussions, some developers and Generators argued for the development of commercial mechanisms such as a frequency response market instead of a mandatory capability requirement in the Grid Code. It is understood that Ofgem would take this forward through the appropriate fora.

<u>Negative Phase Sequence</u>

14. The transient negative phase sequence requirement for faults at 132kV has been removed. The requirement remains for faults at 400kV or 275kV. The transient negative phase sequence requirement i.e. that under a two-phase fault condition has been included under the fault ride through requirement.

<u>Fault Ride Through</u>

15. Several changes have been made to this requirement. References to mechanical power have been removed and replaced with active power. A voltage-duration profile has been added for voltage dip disturbances of durations greater than 140ms where active power can be reduced in proportion to retained voltage whilst supplying maximum reactive current to the network. In addition, active power should be restored to at least 90% of maximum available level within 1 second of the voltage recovering to 90%. A new Appendix has been added in the Connection Conditions to clarify the meaning of the voltage-duration profile. Appendix 2 gives additional information on the fault ride through requirement including NGC compliance process.

16. Appendix 3 summarises the current position following the discussions at the second Forum meeting held on 30 April 2004.

OUTLINE OF PROPOSED GRID CODE REVISIONS

17. The wording changes to the proposed Grid Code revisions are currently under preparation and encompass:

    a. Planning Code
    Addition of a dynamic model and data requirement for a power park unit.

    b. Connection Conditions

    Changes to the requirements on power park modules in respect of reactive power/voltage control, frequency control, negative phase sequence and fault ride through.

    c. Data Registration Code
    Additional data items for power park units to cover the inclusion of a dynamic model in the Planning Code.

Recommendation

18. The Grid Code Review Panel is invited to:

    - Discuss the proposed Grid Code revisions
    - Comment on the proposed revisions

19. Having considered comments from GCRP members, National Grid intends to initiate an industry-wide consultation (to run concurrently with the Scottish consultation) on the proposed Grid Code revisions.

National Grid Company plc
Date 14 May 2003

APPENDIX 1: MANUFACTURERS MEETINGS

General

To check the capabilities of current wind turbines and converters, the transmission licensees arranged meetings with the following manufacturers:

Wind Turbine Manufacturers	Converter Manufacturers
Areva (formerly Alstom T&D)	ABB (also System Solutions)
Bonus	Alstom
Enercon	
GE Wind	
NEG Micon	
Nordex	
RePower	
Vestas	

The key areas discussed covered the following topics:

Fault Ride-through
Frequency Range
Frequency Control
Reactive Power and Voltage Control
Negative Phase Sequence
Output Power with Falling Frequency
Power Quality
Modelling

The transmission licensees outlined their requirements, then a discussion followed on the ability of the manufacturer to meet them, their commercial availability and any additional cost over the cost of a standard turbine. The situation regarding the ability to guaranteeing Grid Code compliance was also raised.

Minutes of the meetings were prepared and agreed with the manufacturers and Ofgem but the manufacturers required these to remain confidential. A table of the capabilities was also prepared and which does not relate capabilities to individual manufacturers. A copy of the table is included at the end of this Appendix. A brief summary of the meetings is included below.

Fault Ride Through:

In the past, this area raised the most technical difficulties. Historically, turbines were low voltage connected and were required to trip for network faults through an under-voltage trip set at around 85% of nominal voltage. All manufacturers were aware of EON requirements (covering part of Germany) requiring fault ride-through down to 15% of nominal voltage (at 60kV and above) for 625ms, and were confident of meeting this requirement at the turbine terminals.

The GB requirement for 0% voltage at Supergrid Voltages raised concerns with a couple of manufacturers, however it was pointed out that fault infeed from wind turbines would maintain the terminal voltage at much higher levels (possibly about 30% depending on the magnitude of reactive current the turbines supplied). A couple of manufacturers expressed concern over the loss of system frequency during a 0% voltage fault, however others had no such concerns due to converter developments carried out over the last 15 months or so. The manufacturers expressing concern stated this could lead to disconnection for a few hundred milliseconds, but should not result in a trip of the wind turbine.

The cost of meeting fault ride-through could increase turbine costs by up to 3%, however there may be an overlap of costs between fault ride-through capability and providing a reactive range capability.

Frequency Range:

All manufacturers confirmed that they could meet the requirements and that there is no additional cost involved.

Frequency Control:

All manufacturers confirmed that they used turbines with variable blade angle control (active stall or pitch control), hence frequency control is inherently possible with some modifications to the control system software. Half of the manufacturers stated that frequency control is available at present, and the others can deliver it within one year. The additional cost for this requirement is negligible, as only a software change is required.

Reactive Power and Voltage Control:

All manufacturers can provide voltage control and the MVAR range required. In many cases, additional equipment is required, raising the cost of the turbines by between 1 and 4%. The requirement for voltage control at the Connection Point can be met by using the wind farm SCADA system to measure the Connection Point voltage and send revised voltage set-points to individual turbines. As SCADA systems are an integral part of modern wind farms, this would have a negligible effect on cost.

Negative Phase Sequence:

This area was less well understood by some manufacturers requiring them to do further investigations. Most have now confirmed that they meet the requirement, with confirmation from the rest still awaited.

Output Power with Falling Frequency:

All manufacturers confirmed that they can meet this requirement which also helps in meeting the frequency range required.

SUMMARY OF MANUFACTURER PLANT CAPABILITY MADE PUBLICLY AVAILABLE AT THE FORUM

In the first quarter of 2004, the Transmission Licensees met with 2 power electronic equipment manufactures and 8 wind turbine manufacturers which cover more than 80% of the world market. To maintain commercial confidentiality as required by the manufacturers, the results in the attached table indicate a summary of the plant capabilities without disclosing the manufacturer identity, their products or technical solutions.

Grid Code Requirement	**Technical Capability**	**Commercial Availability**	**Incremental Cost %**
Fault Ride Through CC6.3.15 SDC4.3.1(f)	8 / 10: Yes 1 / 10: Yes with a restriction 1 / 10: Zero impedance faults excluded	8 / 10: Yes, now 1 / 10: Autumn / Winter 2004 – Jan 2005 1 / 10: Yes, now, zero impedance faults excluded	4 / 10: 0 – 1 % on turbine cost 3 / 10: 1 – 3% on turbine cost 1 / 10: Confirmed - Confidential 1 / 10: Confirmation awaited 1 / 10: No answer
Frequency Range 47 – 52 Hz	9 / 10: Yes 1 / 10: Yes with some restrictions	10 / 10: Yes, now	9 / 10: None 1 / 10: Confirmation Awaited
Frequency Control CC6.3.7 SDC4.3.2(b) *(Power electronics manufacturers excluded)*	7 / 8: Yes 1 / 8: Yes with some restrictions	4 / 8: Yes, 2 now, 1 end 2004 and 1 early 2005 2 / 8: LFSM and H response now, P/S mid 2004 / early 2005 1 / 8: Confirmation awaited 1 / 8: Not yet, project dependent	6 / 8: None / Negligible 1 / 8: Confirmation awaited 1 / 8: No answer
Power/Frequency Characteristic CC6.3.3 SDC4.3.1(b)	9 / 10: Yes 1 / 10: Yes with some restrictions	10 / 10: Yes, now	7 / 10: None / Negligible 2 / 10: Confirmation awaited 1 / 10: No answer

LFSM – Limited Frequency Sensitive Mode
P/S – Primary / Secondary Frequency Response
H – High Frequency Response

SUMMARY OF MANUFACTURER PLANT CAPABILITY MADE PUBLICLY AVAILABLE AT THE FORUM

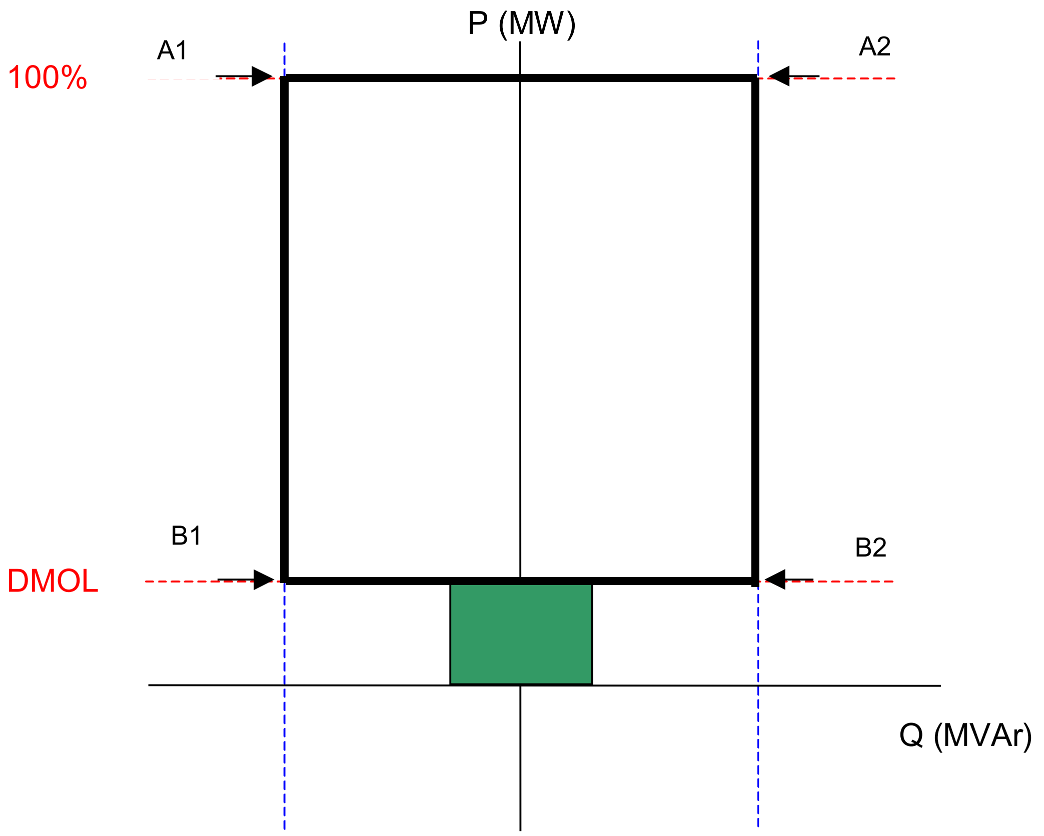
Grid Code Requirement	Technical Capability	Commercial Availability	Incremental Cost %
Reactive Range at Turbine Terminals 0.95 lead – 0.9 lag	9 / 10: Yes 1 / 10: Yes with some restrictions	10 / 10: Yes, now	3 / 10: 0 – 1% on turbine cost 3 / 10: 1 – 4% on turbine cost 1 / 10: - Confirmed - Confidential 2 / 10: Confirmation awaited 1 / 10: No answer
Reactive Range at point of connection 0.95 lead – 0.95 lag	8 / 10: Yes 1 / 10: Yes with some restrictions 1 / 10: Dependant on network	10 / 10: Yes, now	1 / 10: None 1 / 10: 1 – 2% on farm cost 6 / 10: Dependant on network 2 / 10: Confirmation awaited
Zero Mvar transfer at point of connection	8 / 10: Yes 1 / 10: Yes with some restrictions 1 / 10: Dependant on network	9 / 10: Yes, now 1 / 10: Yes	1 / 10: 1 – 2% on farm cost 6 / 10: Dependant on network 2 / 10: Confirmation awaited 1 / 10: No answer
Voltage Control at point of Connection	9 / 10: Yes 1 / 10: Yes with some restrictions	7 / 10: Yes, now 1 / 10: Autumn 2004 2 / 10: Confirmation awaited	5 / 10: None / Negligible 4 / 10: Confirmation awaited 1 / 10: Project size / condition dependant
Negative Phase Sequence CC6.3.10 SDC4.1.3(c)	Steady State 6 / 10: Yes 1 / 10: Yes with some restrictions 3 / 10: Confirmation awaited Transient 5 / 10: Yes 1 / 10: Yes with some restrictions 4 / 10: Confirmation awaited	Steady State 7 / 10: Yes, now 3 / 10: Confirmation awaited Transient 6 / 10: Yes 4 / 10: Confirmation awaited	Steady State 7 / 10: None 3 / 10: Confirmation awaited Transient 6 / 10: - None 4 / 10: Confirmation awaited

Performance Guarantees
Most manufacturers confirmed that industry standard guarantees could be provided for those performance characteristics that can be measured at the time of commissioning. However, an issue remains for those characteristics that cannot be measured such as fault ride through. An understanding of the compliance process in such cases would be important and very useful for the manufacturer.

APPENDIX 2: CHANGES TO THE GRID CODE PROPOSALS

2.1 Reactive Power and Voltage Control

The diagram shown in Figure 2.1 below has been introduced from a proposal made by the BWEA at the last forum (BWEA's diagram was based on the Irish Grid Code proposal). There is no change in this requirement from that proposed in the first consultation, however the inclusion of such a diagram is considered to aid clarity. Within area A1A2B2B1, the plant is subject to MVAr dispatch instructions by the Grid operator. In the green area, with the plant being required to remain reactive power neutral, a tolerance of ±5% of rated MW output around zero MVAr is permitted. In addition, operation in this area is at the discretion of the owner whilst ensuring smooth transition between the two areas.



Point A1 is equivalent to: 0.95 leading power factor at rated MW output
Point A2 is equivalent to: 0.95 lagging power factor at rated MW output

Figure 2.1

For embedded generation plant connected at 33kV or below, the power factor range, which applies within ±5% of nominal system voltage, is modified to adopt the proposal made by the BWEA as shown in Figure 2.2 below. This is a reduction in the requirements for generating MVArs at high system voltages and absorbing MVars at low system voltages. This allows for the lack of transformers with on-load tap-changers that help in the control of the voltage profile within the wind farm.

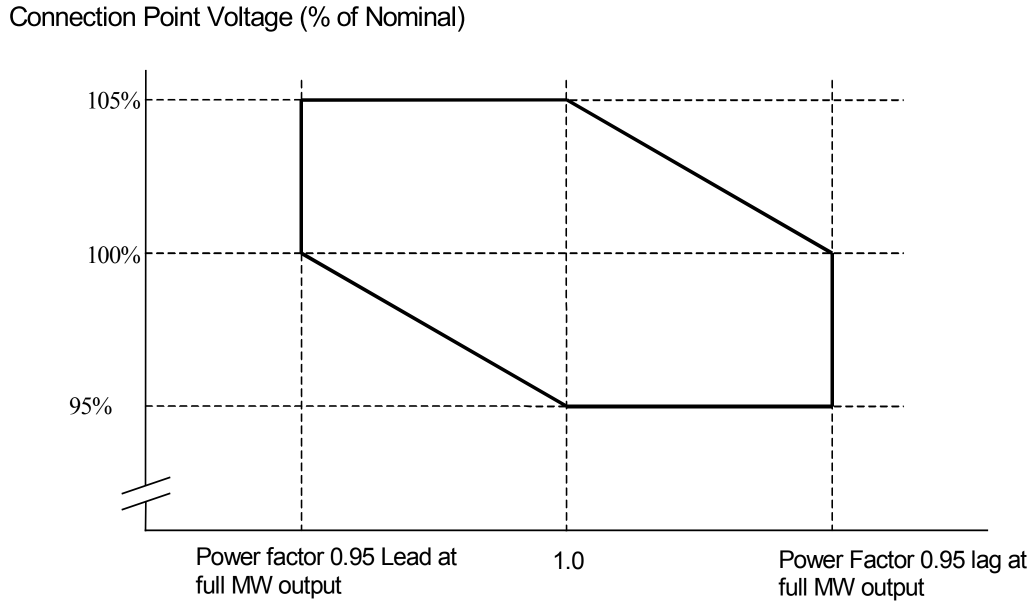


Figure 2.2

2.2 Fault Ride Through (FRT)

General:

There is now a general agreement for the inclusion of a FRT capability although differences remain on the details of the requirement. At the last Ofgem Stakeholder forum, the BWEA and developers proposed a requirement, stated to be based on EON's, for a retained voltage of 15% instead of 0% at 400kV and 275kV however the duration proposed is 140ms rather than EON's 625ms. BWEA extended their 15% proposal to cover 132kV as well.

The 15% retained voltage proposal is unacceptable. NGC studies have demonstrated that with a retained voltage of 15%, large areas of the transmission system would become sterilised allowing only a limited amount of wind farms to connect and preventing further connection of generation in those areas, either renewable or conventional. Figure 2.3 (a, b and c) shows the effect of a fault disconnecting existing generation plant and associated voltage dip propagation illustrating the zone of influence for a 15% and 7.5% retained voltage. Whilst the geographical areas reduce in the case of 7.5% voltage, the same issue remains in terms of wind farm connection restrictions. These restrictions would have a severe impact on the Governments' targets of 10% of electricity requirements by the year 2010 and subsequently 15% by the year 2015.

The stability studies of the NGC transmission system according to the Security and Quality of Supply Standard (SQSS) in both design and operational timescales are based on a solid (i.e. zero retained voltage) close-up 3-phase short-circuit fault criterion. Any changes to the proposed Grid Code FRT requirement to, say 15%, would require a change to the SQSS stability criterion. With the future network designed and operated on this basis, the above restrictions on wind farms would no longer apply assuming that all future wind farms have such 15% capability. However, this would result in a reduction in the system security and stability levels currently enjoyed by customers because transmission system instability could occur in the event of faults with retained voltages of less than 15%. It should also be noted that almost all of the wind turbine manufacturers stated that they can meet the zero voltage requirement based on the fact that they have already developed and tested their plant to meet EON's 15% retained voltage for 625ms at the turbine terminals.

A related question has been posed and that is: can a zero retained voltage at the point of fault occur in reality? The answer is certainly yes. A practically zero voltage can indeed occur at the point of fault for a variety of short-circuit fault causes which include:

a) debris or mechanical items falling onto live equipment such as busbars,
b) circuit breakers inadvertently closed onto safety earths although this is very rare,
c) an insulation breakdown of an underground cable although this is more likely to be 1-phase unless the failure occurs at the cable sealing end,
d) an insulation breakdown in wound equipment, which is more likely to be 1-phase, such as transformers and reactors near the line-end of windings due to steep-fronted lightning or switching surge overvoltages,
d) overhead line faults which can be caused by lightning strikes, snow/ice, rain, wind/gale, pollution, adjacent fires, etc.

Fault statistics on the NGC system show that a significant number of circuit trips are caused by the weather and about 93% of those weather related circuit trips are caused by short-circuits and hence would result in voltage dips. Lightning is the most significant source of 3-phase faults followed by equipment failures, then rain, gales, and so on. A lightning strike during a storm is equally likely to hit a transmission line or tower 1km or many kms away from a substation.

In the event of a circuit flashover, it should be noted that even when the arc resistance is taken into account, the voltage at the point of fault will still be very low and in the range of 1.2% to 3% as shown in Figure 2.4. The arc resistance is calculated using the well-sknown A C Van Warrington empirical formula found in many power system protection textbooks.

Compliance Issues:

a. Objectives of Stakeholders:

Based on many discussions with all stakeholders, the objectives of the compliance process for the main parties include:

For System Operator:

- Establish compliance with technical requirements, confirming positive contribution to system security.
- Define wind farm characteristics, the basis for contracting Balancing Services.
- Establish and validate models and associated data for the wind farm, for use in evaluating system security in design of the transmission system (dealing with other connection applications) and in system operation.

For Project Developer & Owner:

- Obtain Operational Notification (ON) to allow commercial operation as soon as possible.

- ♦ Certainty of outcome of compliance prior to project commitment - minimise project risk.
- ♦ Define plant capability ready for contracting – maximise commercial opportunities.

For Wind Turbine Generator Manufacturer:
- ♦ Ability to give confidence to Developers/Investors of low risk while minimising own risk exposure
- ♦ Deliver practical compliance at least cost
  - ♦ Maximise activity in factory, minimise project-specific site activity
  - ♦ Streamline process to maximise reuse of approach from project to project
- ♦ Provide effective performance feedback to design / product development

b. Compliance stages in context of FRT:

These are designed to ensure system security, equal treatment (between wind projects and conventional generation) and sensitivity to owner/developers and manufacturers needs.

- *<u>Stage 1: Pre project definition – establish type capability</u>*

Review of manufacturers generic data – establish FRT capabilities, e.g. 15% at generator terminals. Co-operate with manufacturers and their organisations, including FGW of Germany. Answer queries from potential developers considering various plant options about established FRT capabilities to help with initial risk management.

- *<u>Stage 2: Project connection initiation – risk reduction prior to contract let</u>*

Initial compliance meeting where NGC explain compliance process in detail. NGC provide transmission network data to developer (and help to obtain DNO network data where required). Developer (or their agents) to establish by simple calculations retained voltage under fault conditions for the types/makes of plant under consideration), using network data provided. Developer judges likely compliance by reference to NGC for type capability and comparison of the two voltages.

- *<u>Stage 3: Project implementation – formal compliance</u>*

Formal compliance submission is made by the plant owner to NGC with supporting evidence. NGC reviews compliance and confirms OK, or discuss any problems in the evidence. The earlier the compliance submission, the earlier the owner will have confidence in compliance. For key aspects, consideration of compliance information in stages would be accepted.

- *<u>Stage 4: Operation – monitoring of performance</u>*

As with all types of generation, NGC reviews the performance under system disturbances. NGC will compare turbine numbers before and after the fault. NGC aims in a supportive, user-friendly manner to achieve an agreed resolution to any issue arising. NGC provides feedback to plant owners with details about significant failures. Significance is judged in context of the severity of the actual fault. NGC will provide helpful monitoring information as available and then request the plant owner to:
- Explain the cause(s)
- Define any remedy that may be needed to avoid repeated and wider reaching failures
- Propose the time-scale for implementation of any remedy

In NGC's long experience with compliance monitoring, this supportive approach always provides solutions. However, in extreme cases of non-co-operation, the Grid Code OC 5.6 'Dispute Resolution' defines the formal process for dealing with disputes. An illustration of the generic and project-specific compliance process is shown in Figure 2.5.

Voltage - Duration Profile:

A voltage – duration profile is introduced as shown in Figure 2.6 to explicitly specify the expected performance requirement for voltage dips durations greater than 140ms. This performance is expected to be inherent in the existing conventional generation plant connected to the transmission system. The voltage - duration profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response of a busbar or a machine terminal voltage to a given network disturbance. Rather, each point on the profile represents a voltage level and an associated time duration which connected plant must withstand or ride through. Figure 2.7 (a to e) illustrates the meaning of the voltage-duration profile for durations up to 140ms (a and b) and greater than 140ms (c, d and e) i.e. in the shaded area of Figure 2.5.

Voltage dips and durations of up to 1 second can occur due to a variety of reasons. Transmission system faults that are cleared in back-up protection times due to either failure of main protection or communication signalling particularly in the case of power line carrier intertrip schemes where the signal is transmitted over the faulty circuit. In such cases, the remote end distance protection which does not 'see' a fault in its zone 1 beyond 80% of the circuit, will operate in zone 2 times which are typically set at 500ms. Zone 3 distance protection designed to operate for remote faults have operating times typically set at around 1 second. Un-cleared faults on distribution systems by main and back-up protection would be cleared by transmission system transformer back-up protection and would also result in long durations voltage dips. In addition, in the event of circuit-breaker failure to clear a fault, circuit-breaker fail protection times are typically set at around 300ms.

The requirement of 80% voltage for 3 minutes in essence means that the plant will have to remain connected and transiently stable during the transient period of typically 5 to 10 seconds following a dip in voltage to 80% from near nominal. Having done so, and provided that the plant is not thermally overloaded, then there would be no difference in the duty the plant is subjected to between 10 seconds and 3 minutes and the plant should be capable of continuing to operate for the required 3 minutes.

At around the 1200ms duration, the requirement is to ensure that generation tripping does not occur in the event of low frequency (about 0.4Hz) high amplitude voltage oscillations. The reasoning behind the 3 minutes is to ensure that generation tripping does not occur following a secured event on the transmission system e.g. a double circuit fault outage. This can cause a voltage step change (this is measured 5 to 10 seconds after circuit tripping to allow transient oscillations to die out) of up to –12% reducing the transmission voltage to say, 88% from say, nominal, followed about 10 to 20 seconds later by automatic on-load tap-changing on distribution and transmission transformers and continuing over the next 2 to 3 minutes. This has the classical effect of gradually raising the distribution system voltages and hence the demand (MW and MVAr), which in turn causes gradual reduction in transmission system voltages towards the 80% level. Generation tripping during this slow automatic dynamic voltage change process can trigger widespread transmission system voltage collapse and blackout. In addition, the 80% for 3 minutes requirement is co-ordinated with electric motors specifications (415V and below, and 3300V and above) which require a capability of operation at 75% voltage for 5 minutes at full load.

Since the requirement in the shaded area in Figure 2.6 allows active power output to be reduced in proportion to retained voltage and the reactive power output would not be required to exceed the continuous capability, the plant would not be thermally overloaded.

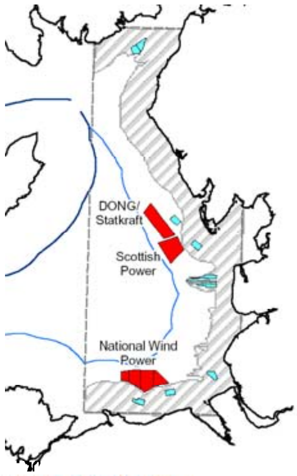
Active power should also be restored to at least 90% of the maximum available power within 1 second of the supergrid voltage recovering to 90% of nominal. This avoids significant loss of active power infeed for long durations and most manufacturers have stated that this is achievable.

APPENDIX 3: SUMMARY OF CURRENT POSITION FOLLOWING SECOND FORUM MEETING ON 30 APRIL 2004

Requirement	Transmission Licensees	Developers
Fault Ride-through	Existing system security and stability levels for secured events (as per the SQSS) require retention of 0%. Relaxation on wind farms would create restrictions in several areas where offshore wind farms are to connect e.g. the Wash, North West and Thames	Should only be required to 15% voltage, and then only on wind farms of over 100MW
Frequency Range	Requirement can be met.	
Frequency Control	Requirement can be met at negligible cost. Post BETTA, Generators in Scotland will be paid for service.	Should not be required until wind farms are constrained off due to lack of available response. This is despite higher cost of fitting the capability at that time. Commercial mechanisms should be developed to replace the mandatory capability requirement.
Reactive Power / Voltage Control	Requirement can be met, but cost may be an issue.	
Negative Phase Sequence	Transient requirement helps system integrity and network resilience under main protection failure scenarios. Changes which would affect all generation plant should be considered in more detail outside the present exercise.	Fault duration should be reduced to normal clearance times, rather than backup clearance times

Figure 2.3 (a)

Crown Estate Announced Sites For Offshore Wind Farms - North West



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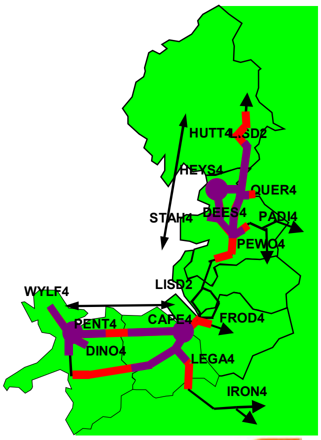
- Round 1 - Total MW = 732 MW
- Round 2 - Total MW = 1700 MW

Total MW = 2432MW

Wind Farm Connection Restriction
Fault Ride Through – North West Coast Only

CONQ: 750MW
DEES: 530MW
HEYS: 1320MW



North Wales Coast:
121 km at <7.5% (purple)
243 km at <15% (red)
+
North Western Coast:
67 km at < 7.5% - purple
134 km at < 15% (red)
becomes sterilised

National Grid Transco

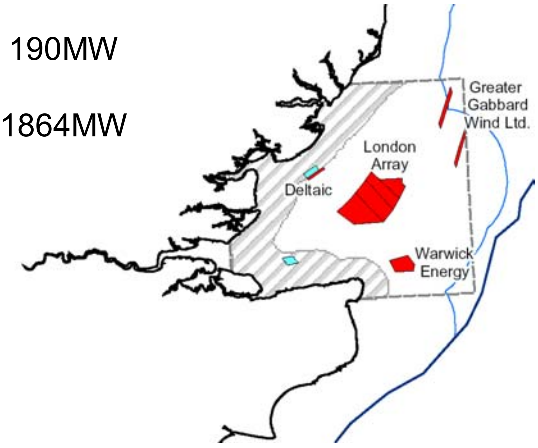
SP Transmission & Distribution

Figure 2.3 (b)

Crown Estate Announced Sites For Offshore Wind Farms - Thames

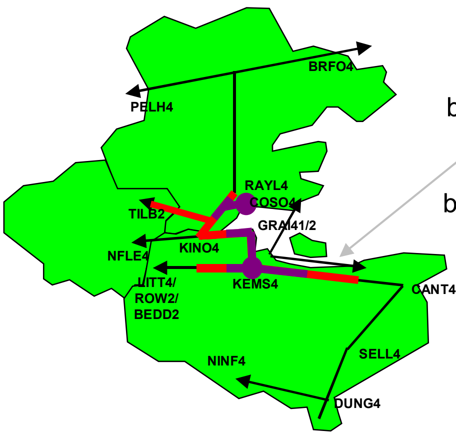
- Round 1 - Total MW = 190MW
- Round 2 - Total MW = 1864MW

Total MW = 2054MW



National Grid Transco

Wind Farm Connection Restriction Fault Ride Through - Thames - Summary



83 km of Thames Coast becomes sterilised at 15% voltage and 41km of Thames Coast becomes sterilised at 7.5% voltage

GRAI: 1320MW
CORY: 720MW
DAMH: 805MW
MEDW: 700MW

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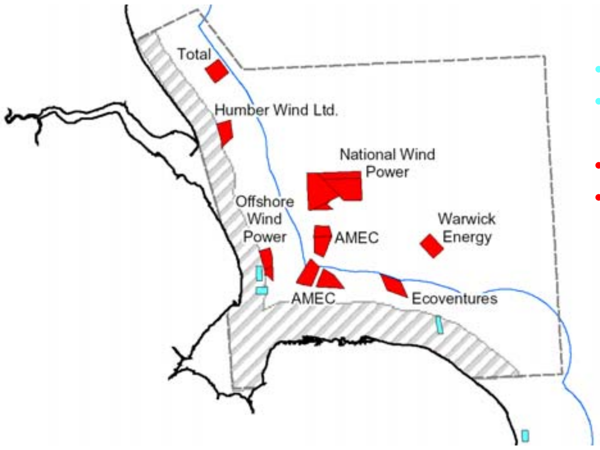
Figure 2.3 (c)

Crown Estate Announced Sites For Offshore Wind Farms - Greater Wash



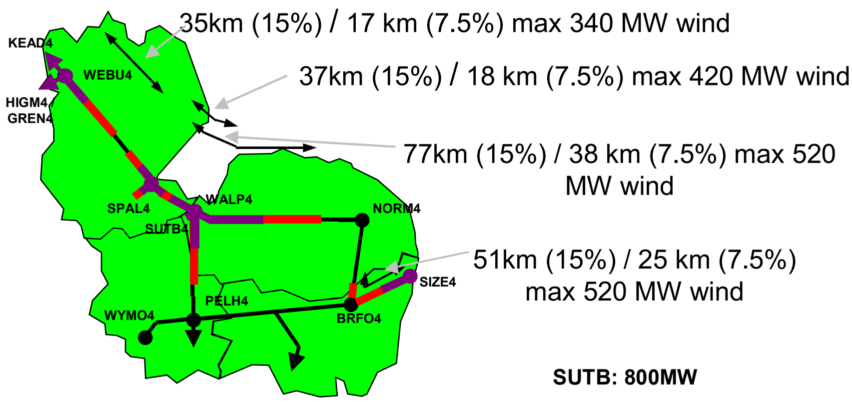
- Round 1
- Total MW = 396MW

- Round 2
- Total MW = 3605MW

Total MW = 4001MW

National Grid Transco

Wind Farm Connection Restriction
Fault Ride Through - Greater Wash Coast Only



SUTB: 800MW

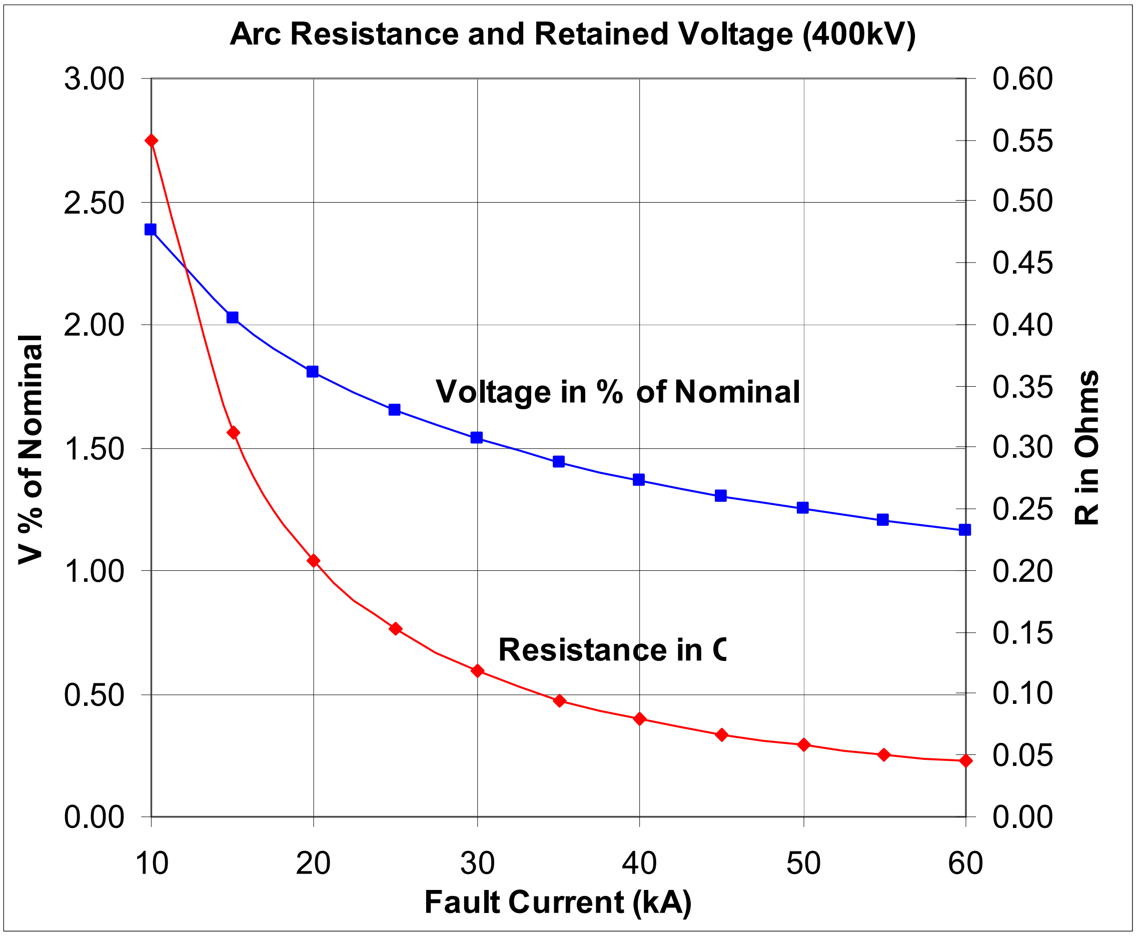
SPAL: 900MW

WBUR: 980MW

SIZE: 660MW

National Grid Transco

Figure 2.4


Arc Resistance and Retained Voltage (400kV)
V % of Nominal
R in Ohms
Voltage in % of Nominal
Resistance in C
Fault Current (kA)
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0.60
0.55
0.50
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
10
20
30
40
50
60

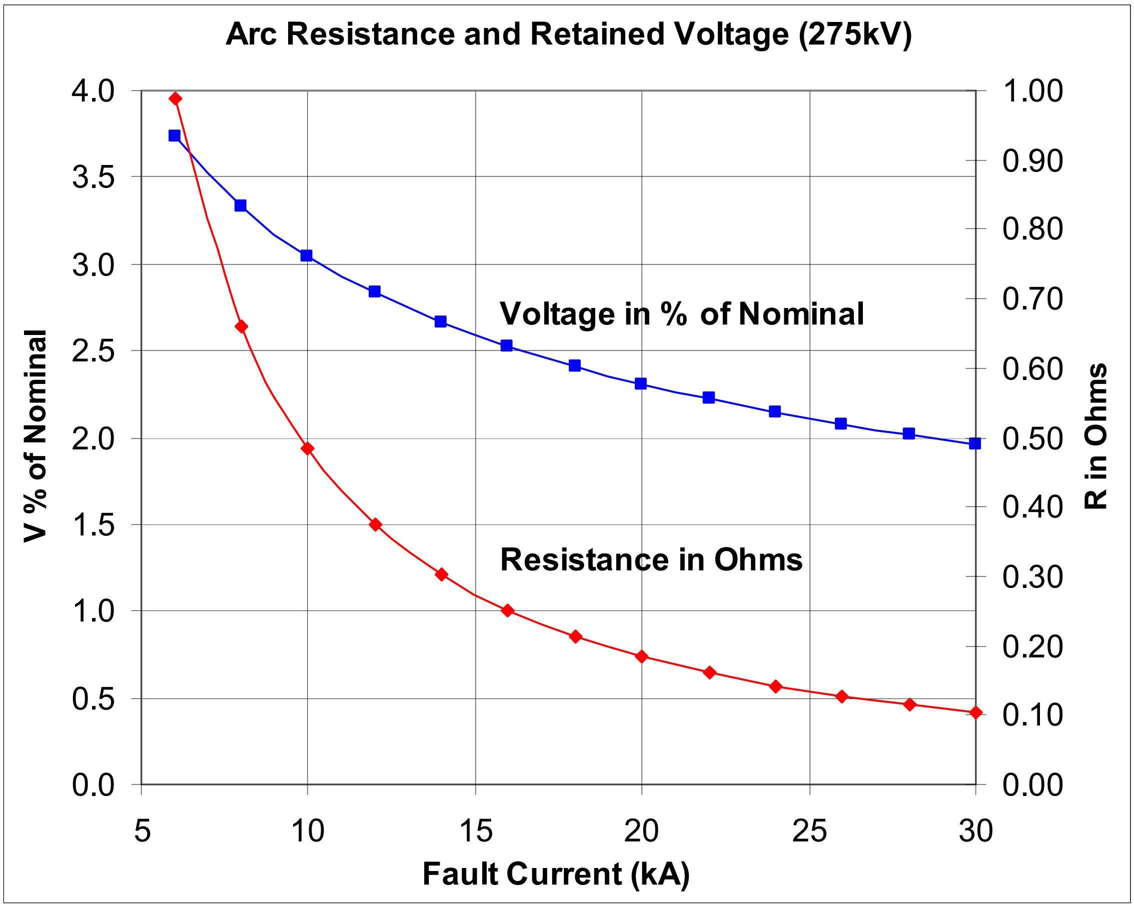

Arc Resistance and Retained Voltage (275kV)
V % of Nominal
R in Ohms
Voltage in % of Nominal
Resistance in Ohms
Fault Current (kA)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
5
10
15
20
25
30

Figure 2.5
Compliance Process

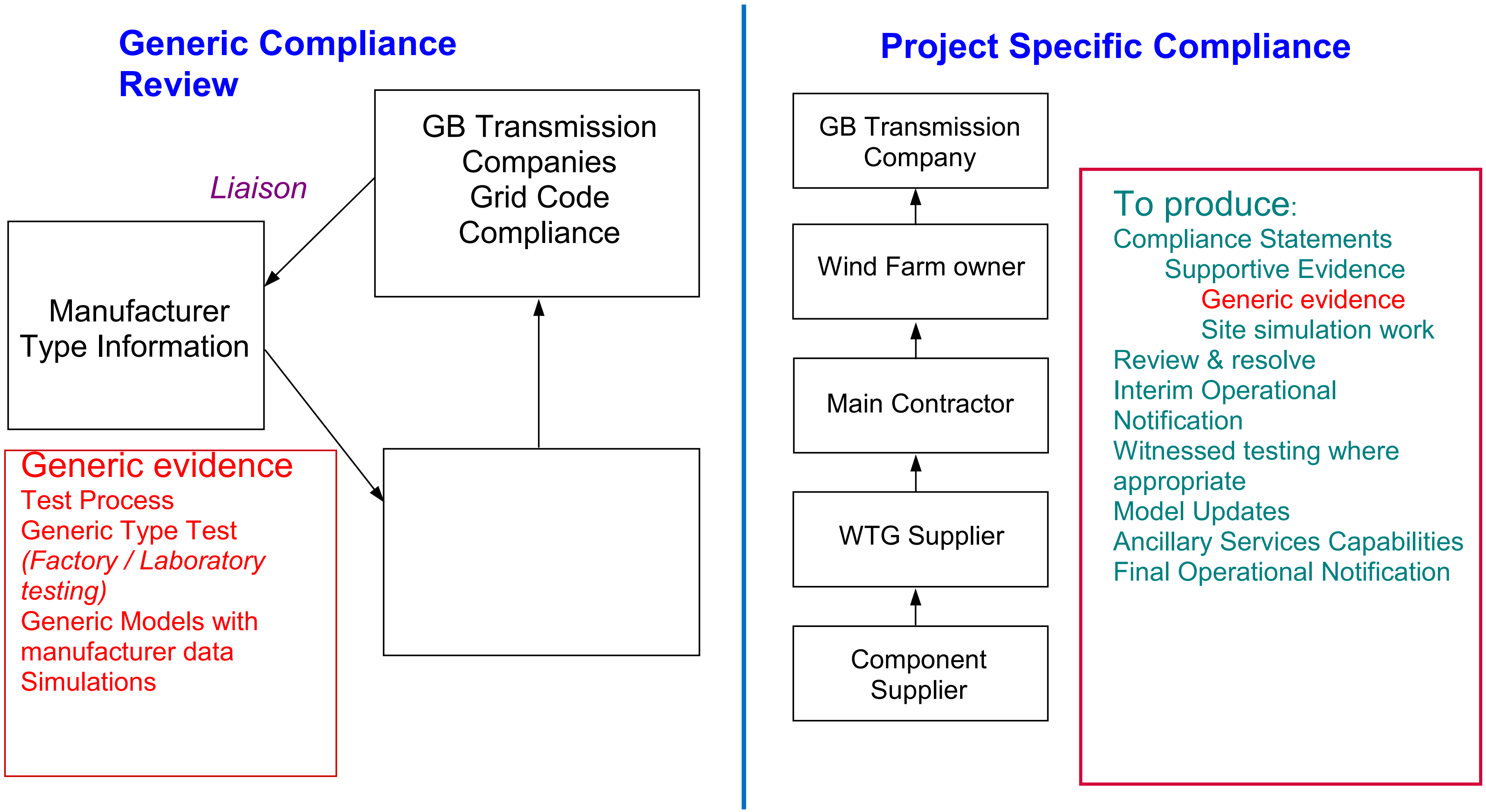


Figure 2.6

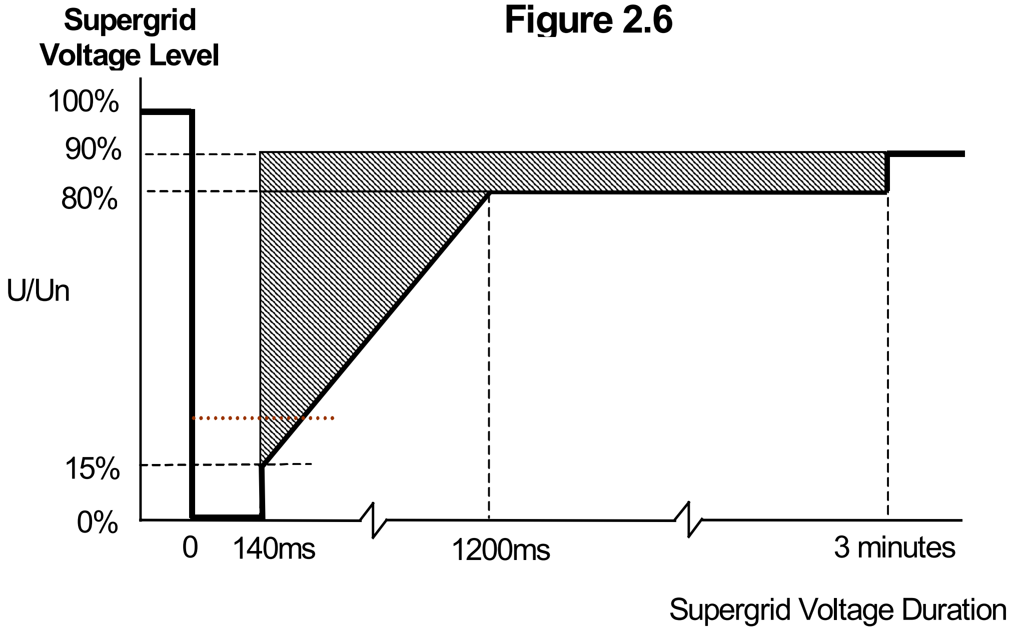
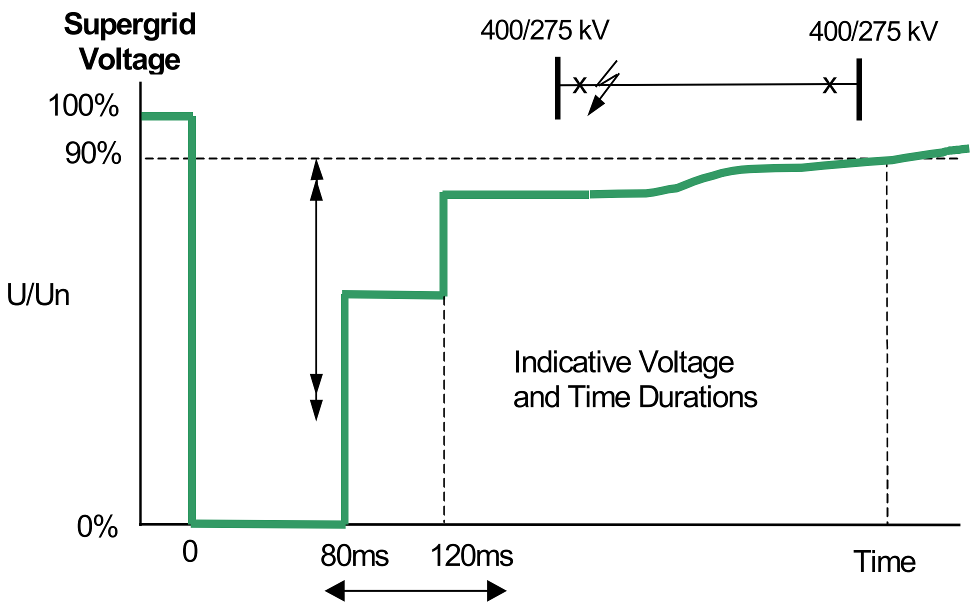
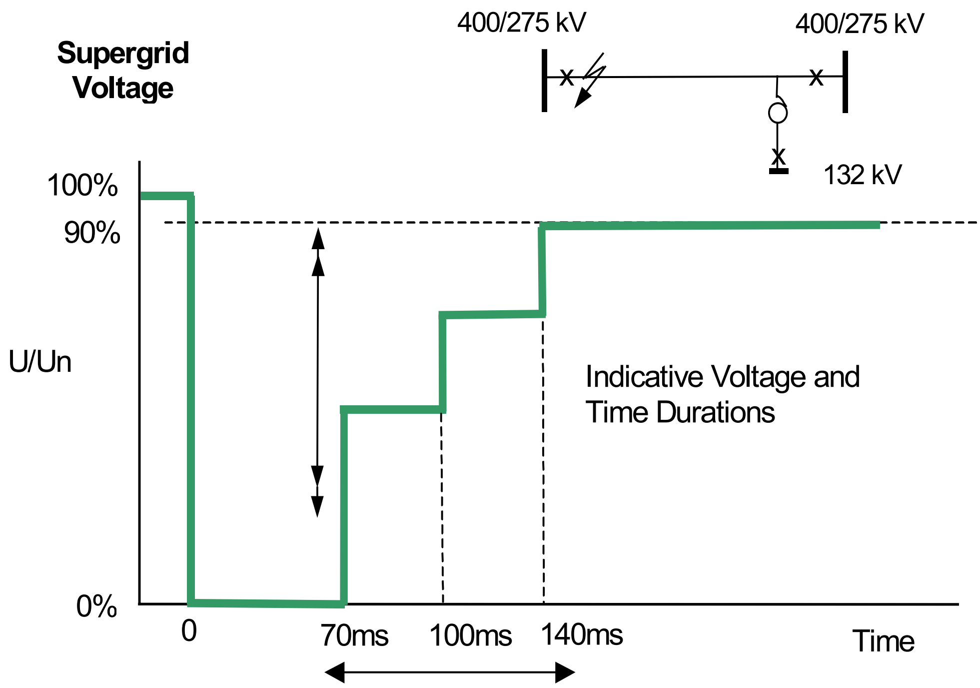


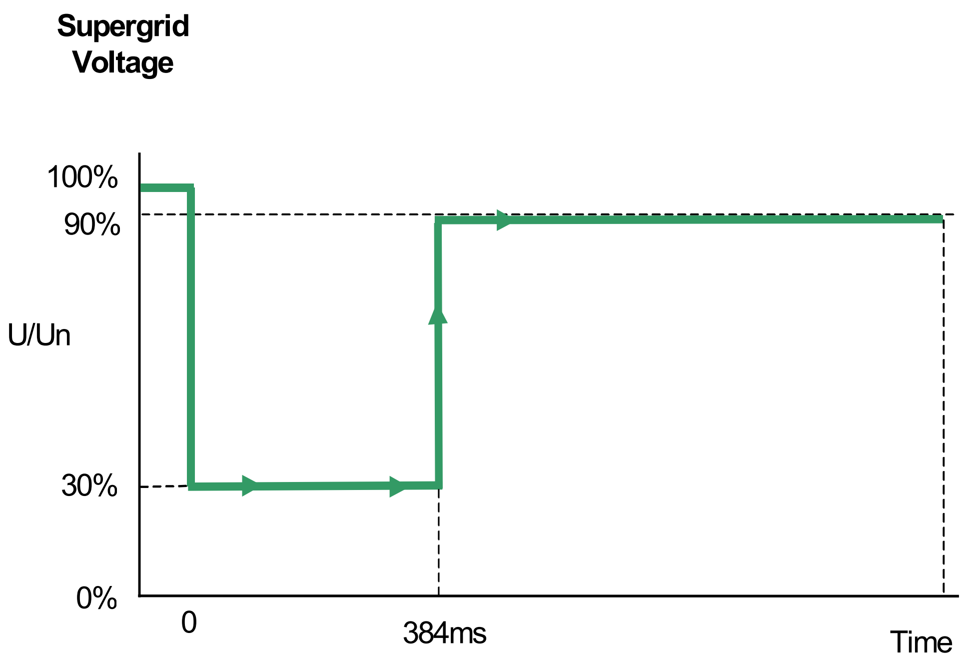
Figure 2.7



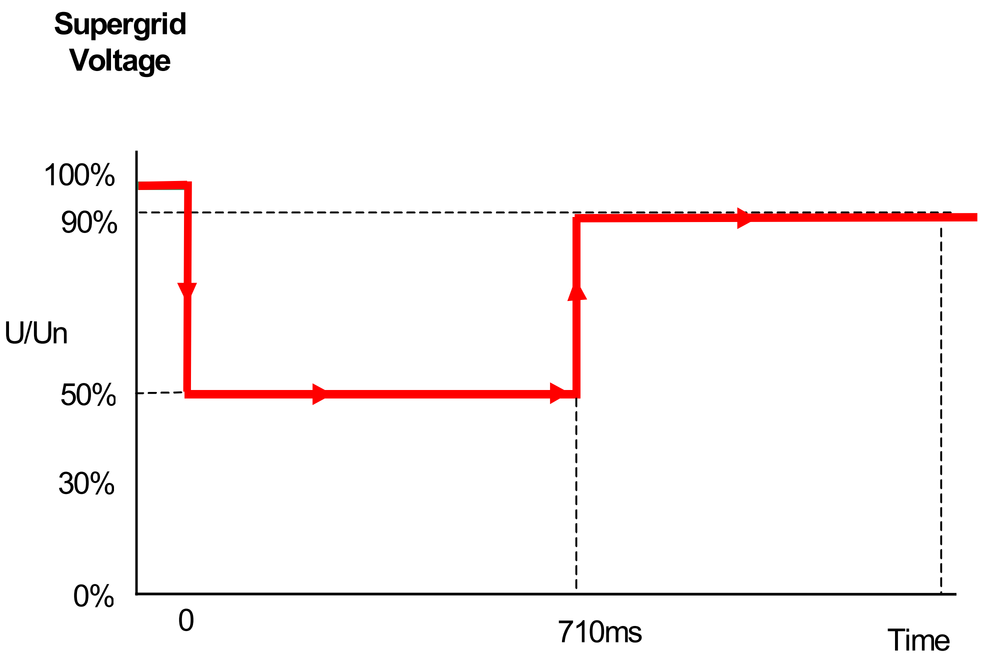
a) Typical fault cleared in less than 140ms: 2-ended circuit



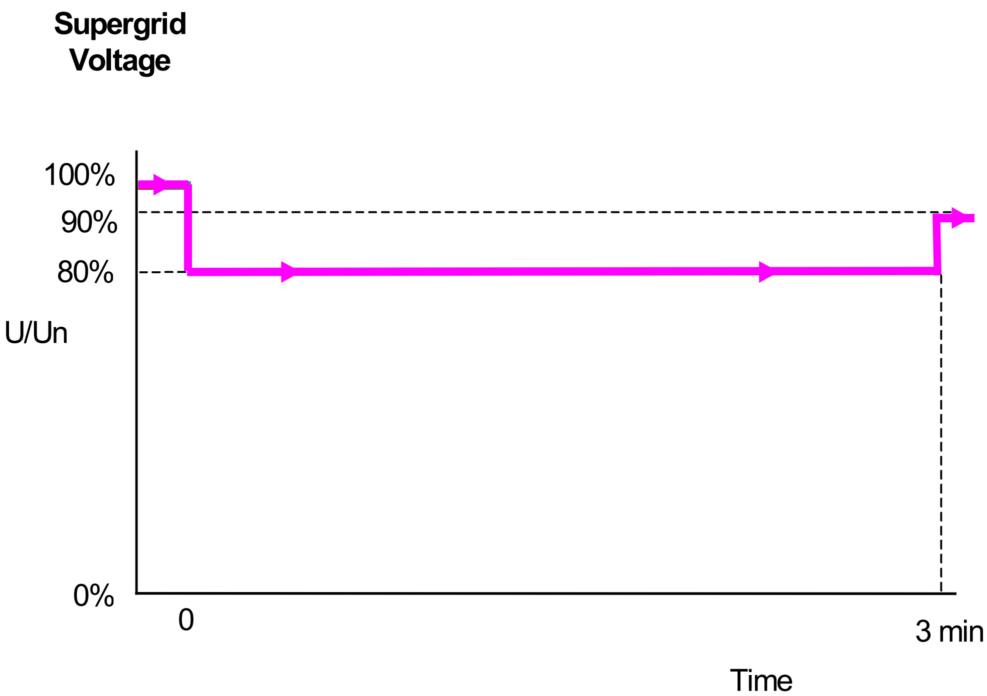
b) Typical fault cleared in less than 140ms: 3-ended circuit



c) 30% retained voltage, 384ms duration



d) 50% retained voltage, 710ms duration



e) 80% retained voltage, 3 minutes duration