GCRP Nov15 pp15/136

Stage 02: Industry Consultation

Grid Code

01	Workgroup Report
02	Industry Consultation
03	Report to the Authority

GC0075 – Hybrid STATCOM's / SVC's

This Consultation seeks views on proposals to modify the Grid Code. The modifications are intended to provide clarity on the interpretation of continuous voltage control as applied to Hybrid STATCOM's and SVC's with a view to clearly defining a repeatability criteria.

Published on:	**7 December 2015**
Length of Consultation:	**20 Working Days**
Responses by:	**6 January 2016**

National Grid recommends:
Implementation of the changes proposed to the Grid Code

High Impact:
None

Medium Impact:
Owners and Developers of Power Park Modules; Manufacturers of Hybrid Statcoms
Transmission Licensees

Low Impact:
None

Contents

Any Questions?

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1 About this document

This Industry Consultation outlines the information required for interested parties to form an understanding of a defect within the Grid Code and seeks the views of interested parties in relation to the issues raised by this document.

Parties are requested to respond by **6 January 2016** to grid.code@nationalgrid.com

Document Control

Version	Date	Author	Change Reference
1.00	19-03-2015	National Grid	Version for GCRP Review

2 Executive Summary

2.1 Under CC.6.3.8 of the Grid Code, Power Park Modules, DC Converters and OTSDUW Plant and Apparatus are required to control the voltage at the Grid Entry Point or Interface Point as applicable. In addition the performance requirements of the voltage control system are defined in Appendix 7 of the Grid Code connection conditions.

2.2 A number of Generators have questioned the definition of continuous voltage control as some Hybrid reactive compensation plant was being considered for a derogation as result of Compliance Testing. This issue was consequently referred to the Grid Code Review Panel.

2.3 In response, the Grid Code Review Panel initially expressed the view that all plant connected after 1 of January 2013 should be capable of responding at least two times over its full reactive range to events which occurred at intervals of 15 seconds or greater. In addition the Grid Code Review Panel convened a Workgroup to investigate these issues further and report its findings back to the Panel.

2.4 To address these concerns, the working group considered a variety of data relating to studies, statistical analysis of weather events, technical solutions and commercial implications. The Workgroup's objective was to define an appropriate level of service required to ensure the robustness and integrity of the Transmission System whilst at the same time maintaining technological neutrality and ensuring Hybrid STATCOM's and SVC's could be used by developers as a solution to meet any proposed requirements.

2.5 The two specific issues which came to light during Compliance Testing where in relation to the switching of the shunt devices:

(i) The time taken to charge the operating mechanism of the circuit breaker could be significant e.g. the spring recharge time; and

(ii) After switching a shunt capacitor out of service, there may be a significant delay while the capacitor is discharged before the plant can be switched into service again.

2.6 Both issues mean that the shunt device is unable to provide voltage control if called upon twice or more in a short time. Where this period of unavailability cannot be accommodated by the short term capability of the equipment there is a shortfall in the reactive capability available to contribute to the control of system voltage. The time delay before full reactive capability is restored exceeds 10 minutes in some cases.

2.7 During the meetings, various other technical issues were raised and discussed including communications delays, and short time ratings.

2.8 In addition to the above, consideration was also given to the fault ride through capability of the switched reactive elements as compliance testing had also identified cases where switches were opened under low system voltage conditions. This was a concern because low voltage depression can be seen over a wide geographic area when a fault is applied and may result in a considerable reduction in reactive power post fault, leading to either high or low voltage and possibly voltage collapse. It was considered important to cover both voltage control and fault ride through to ensure that repeatable performance and the fault ride through requirements of STATCOM's were clearly defined and understood.

2.9 The proposed solution asks for voltage control to be provided with a repeat capability at 15 seconds but limited to 5 events in 2 minutes up to a maximum of 25 events a day. Further clauses are proposed to be added to Balancing Code emphasising the need to notify the Control room of limited reactive capability.

2.10 The proposal was developed by the workgroup after consideration of the issues raised by generators, developers and manufacturers alongside those raised by Transmission Licensees. The proposed requirements are intended to strike a balance between the minimum need of the Transmission System and cost impacts on developers and manufacturers. The proposed solution represents the lowest cost option of the potential solutions considered by the workgroup.

2.11 The proposed change provides assurance of equipment performance in planning and operational time scales, giving the operators confidence that equipment's is able to respond within DAR timescales. It also clearly sets out procedures for limited availability.

2.12 The proposed change also aims to address concerns over the clarity of current requirements and to allow manufacturers and developers to compete on an equitable basis. Whilst most manufacturers and developers have cited some increases, others have indicated marginal, no increase or the potential for cost reduction. It also ensures there is no need to rely on some generators exceeding the requirements to make up for shortfalls elsewhere.

2.13 The Workgroup reached the conclusion that the legal text provided in Annex 3 of this document, should proceed to industry consultation. The text includes a new clause CC.A.7.2.3.2, which defines the repeatability performance requirements, modifications to CC.6.3.15.1 and CC6.3.15.2, which state switched reactive components should ride through a fault without opening or closing switches; and the modification of clause BC2.11.4 of the Balancing Codes specifying how Power Park Modules should notify the control room in the event of limited reactive capability resulting from CC.A.7.2.3.2.2.15 It is believed the draft legal text in Annex 3 of this consultation addresses:-

- The time frame required for a Power Park Module or Reactive Compensation equipment to transit from full lead to full lag or vice versa.
- Clarifications to the settling time following a disturbance
- The addition of a repeatability criteria requiring 5 consecutive responses in any five minute period, no more than 15 seconds apart.
- A criteria which limits the maximum number of events (ie unity to 90% full leading or unity to 90% full lagging) to a maximum of 25 events in any 24 hour period.
- Where the daily limit of 25 events is exceeded the requirement to inform NGET of the reduction in reactive capability which should be available as soon as possible but in any event no longer than 6 hours after the reduction
- Amendments to the fault ride through requirements clarifying reactive compensation equipment and requirements preventing them from switching during a fault ride through sequence.

2.16 These proposed amendments have been introduced to section CC.6.3.15 and CC.A.7.2.3 of the Connection Conditions and BC2.11.4 of the Balancing Code. A majority of the Workgroup members who expressed a view believe the changes address the original Grid Code defect.

3 Purpose & Scope of Workgroup

Overview

3.1 An issue was initially raised at the Grid Code Review Panel in 2010 in relation to CC 6.3.6. This requires that all generators should be capable of contributing to voltage control by continuous changes of reactive power. In addition, CC.6.3.2 defines the reactive capability required from Power Park Modules at the Connection Point whilst CC.6.3.8 and Appendix 7 of the Grid Code Connection Conditions defines the necessary voltage control and performance requirements.

3.2 A number of Generators questioned the definition of continuous voltage control and the fault ride through requirements with respect to the reactive compensation plant installed as part of a Power Park Module.

3.3 After an initial Workshop meeting in September 2013 a Workgroup was established in November 2013.

3.4 The Workgroup was tasked to consider the following points:

3.4.1 The performance of Hybrid Static Compensators and comparable equipment with respect to repeatability and the supply of reactive current during a fault.

3.4.2 The performance required from voltage control equipment within Power Park Modules to control voltage on the networks, during and after secured events, and in the event of a wider system disturbance.

3.5 In addition to the points in 3.4, the workgroup discussed the relevant sections of Balancing Code (BC2.A.2.11.4). Further to this, the interactions between this section and the Grid Code Connection Conditions and the relevant provisions of ENTSO-E RfG were also considered to ensure that the workgroup's proposals do not conflict with future requirements.

Timescales

3.6 The work group was scheduled to report back to the Grid Code Review Panel at regular intervals with the aim of completing a report at the end of the first year.

3.7 In the event, five work group meetings were held which took just over a year with the group rapidly converging on a conclusion. Consequently it was decided to produce a report containing the findings and conclusion.

3.8 The final work group meeting was held in April 2015 and it was decided to submit the report to the Grid Code Review Panel in July 2015.

3.9 The Panel asked the Workgroup to reconsider some aspects of how its proposals were expressed in the proposed legal text and revisions were agreed and included in a final Workgroup report, and are provided in Annex 3 of this document.

Workgroup Meeting Dates

M1 – 15 May 2014
M2 –07 August 2014
M3 – 22 October 2014
M4 – 26 January 2015
M5 - 27 April 2015

4 Background

4.1 This section describes the development of this issue from initial identification in 2010 to the beginning of the Workgroup.

4.2 May 2010 Panel Meeting - The issue was first raised in the GCRP minutes under 'Any Other Business' at the Grid Code Review Panel. A representative for the Wind Farm developers highlighted an issue relating to MSC's used in PPM voltage control systems.

4.3 September 2010 Panel Meeting - NGET submitted a paper to the September panel meeting "GCRP pp10/24 Voltage Control and Fault Ride Through". The key recommendations were:

- Sites with a Completion Date prior to 1 January 2013 and have a performance such that switch recharge time (close-open-close) less than 15 seconds and capacitor discharge time less than 2 seconds will be accepted.
- Sites with a Completion Date prior to 1 January 2013 and have longer unavailability would be asked to seek a derogation.
- Sites with a completion date after 1 January 2013 would be required to have no unavailability of reactive capability.

4.4 The Grid Code Review Panel and STC Panel were asked to consider if any changes were required to either the Grid Code or / and the STC.

4.5 November 2010 Panel Meeting – At this meeting National Grid presented the following options for the panels consideration:

1. Treat all affected developments as non-compliant

   Potentially - 30 derogated developments

   No incentive for installations with long delays to improve

2. Adopt NGET's proposal for an interim interpretation

   Removes uncertainty for immediately affected developments

3. Amend Grid Code to reflect NGET's proposal for an interim interpretation

   Removes uncertainty for immediately affected developments

   Need to assess change for wider impact

4. Review the application of hybrid reactive power and voltage control solutions in meeting the Grid Code requirement

   What are the incremental costs of 'true continuous' operation?

4.6 The panel decided on option 3.

4.7 February 2011 Panel Meeting - The issue was discussed and it was agreed to resolve the issue of interim interpretation of the Grid Code with an extraordinary meeting if necessary.

4.8 November 2011 Panel Meeting - The Panel agreed that NGET should bring forward a change to the Grid Code to clarify the meaning of "continuous" in relation to voltage control and switched capacitors/ reactors.

4.9 Additionally it was determined the Panel must decide how projects should be dealt with in the meantime.

4.10 March 2011 Extraordinary Meeting of the GCRP – At this meeting a paper was submitted by a representative of the developers which made recommendations in two sections, (A) specific to this issue and (B) generic, to deal with different interpretations of the Code:

A. Provide interpretation and progress Code change process as follows:

1. Ensure that NGET bring forward a Grid Code change proposal to remove the uncertainly of interpretation of "continuous" regarding voltage control and

especially in relation to capacitor switching and discharge. (NGET's action had already been agreed at the GCRP in November 2010).

2. Ensure that NGET perform a Cost Benefit Analysis for any changes proposed in (1) above.

3. Ensure that NGET assess the risk to the NETS of legacy plant and consider a retrospective application of the Grid Code change.

4. For existing projects or those under construction (pending the Grid Code change), define an interpretation of the current Grid Code term "continuous" in relation to voltage as either:

   a. In defining "continuous" - ignore the time delay in the second switching operation of a capacitor or reactor.

   Or

   b. Define "continuous" in the current Grid Code to mean a minimum of 15 seconds (close-open-close) and 2 seconds (capacitor discharge) for an indefinite number of repeat operations.

   Or

   c. Define "continuous" in the current Grid Code to mean a minimum of 15 seconds (close-open-close) and 2 seconds (capacitor discharge) for a second switching operation with no specified requirement for a third switching operation.

5. To assess any potential discrimination issues, NGET to provide a list of all projects which have switched voltage control equipment commissioned to date, clearly showing the capabilities and indicating where NGET has demanded a change to capabilities and where FONs have been issued or have not yet been issued.

B. Make Code changes to manage different interpretations of the Code:

6. Ask NGET to bring forward a change to the General Conditions of the Grid Code to require NGET to bring to the Panel any issue of interpretation of the Grid Code where two or more Users are disputing NGET's interpretation and for such a report to be a standing agenda item for Panel meetings.

7. Ask NGET to report under KPIs on the speed of resolution of matters of interpretation requested by Users.

8. To provide a Web based facility for Users to request such interpretations.

4.11 From the meeting minutes the panel decided:

4.11.1 In confirmation of **Recommendation A (1)** the Panel agreed that both parties should discuss the issue further and draft a Consultation document, which would apply to future projects and if necessary and justified, be proposed to apply retrospectively. The Panel agreed that **Recommendations A (2) & (3)** should be considered and used if appropriate.

4.11.2 The Panel agreed, that as existing wind farm projects original interpretation, as described under **Recommendation A (4a)**, had not caused an operational issue, these projects will not need to seek a derogation and are deemed to be compliant. **Recommendation A (5)** was therefore deemed unnecessary.

4.11.3 The Panel also agreed that there was a future issue for anticipated, larger plant and therefore a future change to the Grid Code was likely to be needed to provide a clear and unambiguous obligation on such plant. Such an obligation would be applied to plant connecting after a certain date. Dates ranging from 2013 to 2015 had been discussed previously but this would be subject to consultation, if found to be necessary. The Panel noted that this may also need to be applied retrospectively to all projects or some projects (e.g. above a certain size), but only subject to a clear cost benefit case.

4.11.4 The Panel recommended that plant that was under development should be designed to meet the **Recommendation A (4c)** criteria.

4.11.5 The Panel agreed that **Recommendations B (7) and (8)** should be progressed by National Grid but not **Recommendation B (6)** as it would be a significant resource burden for National Grid and the industry and may not be workable.

4.12 Workshop 20 September 2013 – Manufacturers put the case for allowing the use of Hybrid STATCOM/SVCs on cost and capability grounds. National Grid stated it was not aiming to prevent the use of Hybrid STACOM/SVC's but presents a case for improving the future performance. It is agreed that a work group should be convened to consider the matter in greater detail.

4.13 Workgroup November 2013 – First Work group meeting is held to look into the issues.

5 Work Group Discussion

5.1 The work group discussion covered a variety of topics which were discussed over the duration of the work group sessions.. The discussions are covered under the following section of the report under the following headings:

- Voltage Control and Reactive Power;
- Transmission Owner and System Operator Objectives;
- Response of Statcoms/SVCs and effects of Limited Reactive Reserve;
- Lightning Storm Data;
- Winter Storm Data;
- Consistency with the European Requirements for Generators Code; and
- Manufacturers' Survey.

Voltage Control and Reactive Power Provision

Overview of Existing Grid Code Requirements

5.2 The following extracts are taken from the current Grid Code as issued to the workshop in September 2013. Most of the text is shown in light grey with the key words relating to the provision of continuously acting voltage control in highlighted text.

CC.6.3.6 (b)

Each:

(i) Onshore Generating Unit; or

(ii) **Onshore DC Converter** (with a **Completion Date** on or after 1 April 2005 excluding current source technologies); or

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

(iv) **Onshore Power Park Module** in Scotland irrespective of **Completion Date**; or

(v) **Offshore Generating Unit** at a **Large Power Station**, **Offshore DC Converter** at a **Large Power Station** or **Offshore Power Park Module** at a **Large Power Station** which provides a reactive range beyond the minimum requirements specified in CC.6.3.2(e) (iii),or

(vi) OTSDUW Plant and Apparatus at a Transmission Interface Point

must be capable of contributing to voltage control by continuous changes to the **Reactive Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**.

APPENDIX 7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS

CC.A.7.2.2.1 The **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** shall provide continuous steady state control of the voltage at the **Onshore Grid Entry Point** (or **Onshore User System Entry Point** if **Embedded**) (or the **Interface Point** in the case of **OTSDUW Plant and Apparatus**) with a **Setpoint Voltage** and **Slope** characteristic as illustrated in Figure CC.A.7.2.2a..

CC.A.7.2.2.5 Should the operating point of the **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** deviate so that it is no longer a point on the operating characteristic (figure CC.A.7.2.2a) defined by the target **Setpoint Voltage** and **Slope**, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

CC.A.7.2.3.1 For an on-load step change in **Onshore Grid Entry Point** or **Onshore User System Entry Point** voltage, or in the case of **OTSDUW Plant and Apparatus** an on-load step change in **Transmission Interface Point** voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the **Reactive Power** output response of the **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure CC.A.7.2.3.1a.

(ii) the response shall be such that, for a sufficiently large step, 90% of the full reactive capability of the **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, as required by CC.6.3.2 (or, if appropriate, CC.A.7.2.2.6 or CC.A.7.2.2.7), will be produced within 1 second.

(iii) the magnitude of the **Reactive Power** output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change

(iv) the settling time shall be no greater than 2 seconds from the application of the step change in voltage and the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state **Reactive Power** within this time.

(v) following the transient response, the conditions of CC.A.7.2.2 apply.

5.3 These requirements have been interpreted differently by different manufacturers. Some have understood this as a requirement to provide equipment whose response is available at any time with no unavailability between events. Others have understood the requirement as the ability to respond to gradual changes over a long period with occasional sudden extensive changes being delivered with a linear increase.

Implementation of the Grid Code Requirements

5.4 The diagram below shows how the GB Grid Code requirement might typically be met for a given Power Park Module. The red lines in the diagram represent the physical connection of real and reactive power sources to the transmission system through the POC (Point of Connection). The other lines represent the measurement feedback and control signals.

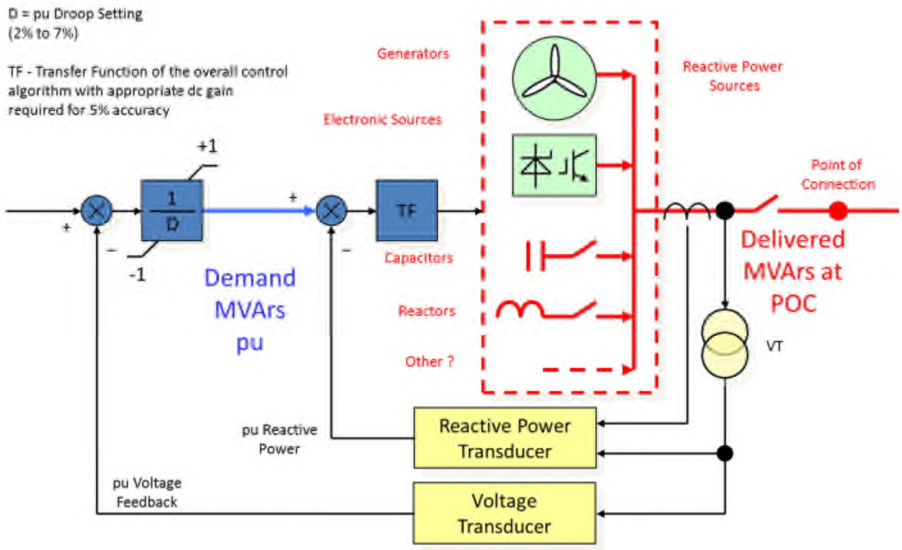


Figure 1: Typical Voltage Control Methodology

5.5 To meet the requirement, single or multiple reactive sources may be used. These may include wind turbines, dynamic compensation elements such as STATCOM's or SVC's, static compensation elements such as capacitors and reactors or any other compensation sources.

5.6 In some applications, the STATCOM or SVC is used with a fixed reactance which simply offsets the range or provides the dynamic response with most of the steady state performance provided by the generators. In others practically all of the reactive power at the point of connection is provided by a STATCOM / SVC or Hybrid STATCOM / SVC.

5.7 In a Hybrid STATCOM or SVC, the dynamic compensation sources are generally used with a combination of mechanically switched capacitive and reactive elements to provide the full range of control required to meet the Grid Code (see diagram below).

5.8 The control system implementations vary too. In some applications, the STATCOM / SVC is the slave and follows instructions from the Power Park Controller whilst in others it's the other way round.

5.9 Developers have raised concerns in relation to the many different configurations and ability to provide repeatable performance. However in subsequent conversations and investigations, these have turned out to be either wider issues which do not specifically affect repeatability (e.g. speed of communications) or are achievable with existing technology.

Typical Hybrid SVC / STATCOM Operating Ranges (50% or 60%
of the steady state reactive power produced by the capacitors and reactors)

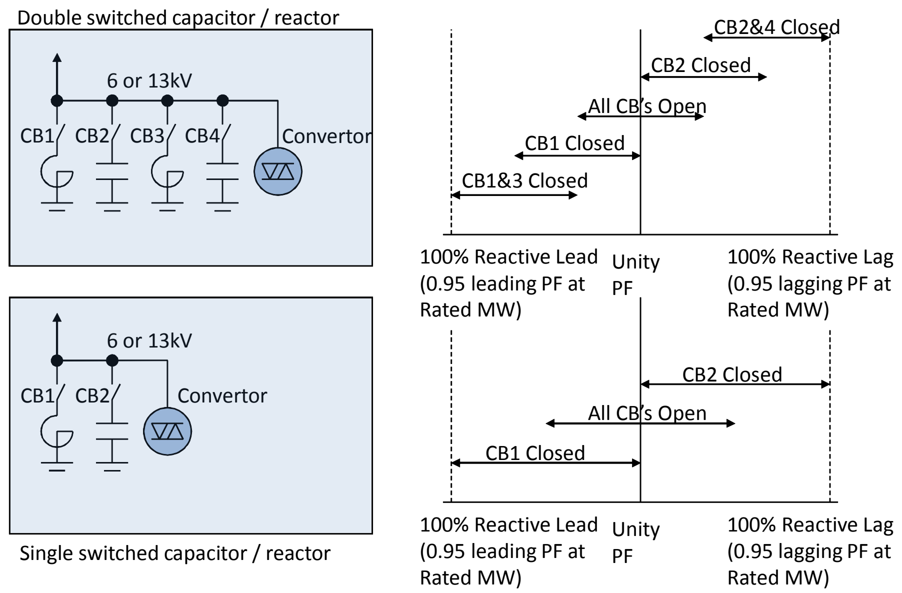


Figure 2: Typical SVC Steady State Operating Methodology

5.10 National Grid's experience, during compliance testing, has identified the ability to close the switches rapidly as the only issue affecting the compliance of Hybrid STATCOM's and SVC's.

5.11 The opening and closing of the switches is generally limited by the spring recharge time and / or in some designs, the need to discharge the capacitors before reclosing.

5.12 Switch reclose times vary depending on switch type and voltage but can typically vary from less than 1 second to 15 seconds for Vacuum Interrupters and HV Switch Gear respectively.

5.13 Some designs require the capacitors to be discharged before closing the switches. The discharge circuits frequently employ resistors or reactors which are only rated for one or two operations after which they require a cooling off period.

5.14 However some manufacturers have overcome these limitations and offer solutions which meet or can exceed the proposed requirements.

5.15 Interestingly one of the work group members is an independent switch controller OEM (Original Equipment Manufacturer) who is not allied to any of the STATCOM / SVC manufacturers and offers a point on wave solution to allow fast Capacitor, Reactor and Transformer switching.

5.16 Their solution removes the need to rapidly discharge the capacitors but incurs some extra cost as the poles of the switch must be independently controlled.

Transmission Owner and System Operator Objectives

5.17 The key objectives of the Transmission Licensees in his workgroup were to:

- Maintain the Post Fault Voltage variation within SQSS Limits
- Prevent Post Fault Voltage Collapse or Over Voltage
- Strike an Economic Balance in achieving the above

5.18 To ensure these requirements are met for all sequences and events which may reasonably be encountered, the Transmission Owners believe it is necessary to ensure switched reactive elements are capable of repeated operations and have fault ride through capability, which are both required to ensure post fault recovery of the voltage.

5.19 An economic balance needs to be struck which considers the robustness and integrity of the Transmission System, the cost to the generator and the capability of the solutions available to equipment manufacturers.

5.20 In the interest of competition and because the requirement is not based on geographic location, the solution should not be site specific or favour a specific type of generation e.g. wind, solar, tidal etc. and should therefore apply to all Power Park Modules, OFTO's and equipment contracted for reactive services.

5.21 Various event types were considered which could result in a perturbation or switching actions leading to a deviation in Transmission System voltage. This included any balanced or unbalanced fault as in GB these typically result in all three phases of the lines being switched out.

5.22 The various event types considered were:

- Lightning
- Storms / High Winds
- Debris on a line (e.g. polythene sheet caught on a line)
- Operator Error
- Voltage Instability
- Ice Forming on Conductors
- Cascade Tripping Events
- Angular Instability
- Interaction Between Controllers

5.23 Considerable evidence for lightning and storms was found but evidence of the other phenomena was more difficult to find. Notwithstanding this, all of the above events are considered to be credible.

5.24 It should be noted that for economic reasons, the solution proposed by this document allows a limit on the number of switching events and the time between events to be limited to a minimum of 15 seconds. A compromise has therefore been struck as dynamic instability, interaction between controllers and some event sequences have not been covered by the proposal in this report.

Repeatability and Line DAR Operation

5.25 The primary drivers for the need for repeatable response in GB are the frequency and multitude of events, which is covered in the later sections and line DAR (Delayed Auto Reclose).

5.26 When a fault occurs on an HV line, the protection system opens the breakers at each end of the line to clear the fault. DAR will automatically reclose tripped circuit breakers after the 'Dead Time' has expired, typically 3 - 20 seconds, bringing the line back into service and re-establishing system security. The dead time allows ionized gas to blow away and/or arc deposits to fall away.

5.27 On re-charging and loading the circuit, a second timer starts, this period is known as the 'Reclaim Time'. Faults during this period will cause a second trip which will lock out the breaker. This period typically lasts 3-4 seconds. The Reclaim Time allows the insulation medium in the breaker (Oil / SF6) time to recover.

5.28 It also ensures repeated faults, which occur within the reclaim time do not result in repeated breaker operation, for example such as a metal ladder left on a conductor or a closed earth switch.

5.29 However if faults repeatedly occur after the Reclaim Time, operator intervention is required to lock the line out. In this scenario, further operator interventions i.e. switching operations, may require additional actions from the Hybrid SVC / STATCOM's.

5.30 Scenarios which cause DAR Operation include:

- Lightning travelling up a line
- Storms / High Winds / ice loading (causing conductor clashing)
- Debris on a line (e.g. polythene sheet caught on a line)

5.31 Switching lines in and out redirects real and reactive power flows and may result in loss of generation, both of which can result in voltage fluctuations requiring response from voltage control systems.

5.32 Multiple lightning strikes or conductor clashing on a specific line or surrounding lines can result in multiple DAR events. As these events are unlikely to occur during the reclaim period this can result in multiple responses from voltage control systems as the post fault power flows are redirected then restored.

5.33 For example, multiple faults on a line between substation A and B shown in Figure 3 can cause changes in voltage V at substation C which require a reactive power (Q) response from the wind farms Hybrid STATCOM / SVC. However DAR restoration of the line restores the voltage and therefore the original value of Q.

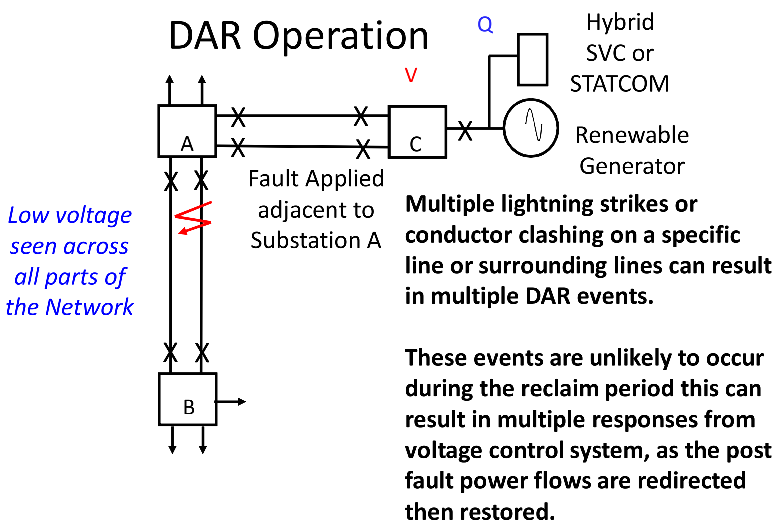


Figure 3: DAR Operation

5.34 Depending on the STATCOM design, droop setting, voltage change and duration of the pulses of Q, the STACOM may or may not be required to switch a capacitor or reactor in or out. However the equipment should be capable of operation at all droop settings and therefore capable of full response for a 2 to 4% change in voltage.

5.35 The diagram below (Figure 4) shows an event sequence of four faults, three of which result in DAR operation but the fourth occurs in the reclaim time and therefore results in the line being locked out. For each fault there is an initial voltage depression lasting 140ms after which the fault is cleared and the voltage recovers to a level which is lower than the target voltage (low volts on the red trace).

5.36 The Hybrid STATCOM/SVC is required to operate within 1 to 5 seconds (depending on the range of the response. For a change in reactive power of unity to 90% of fully lagging operation or fully leading operation, a response time of 1 second would be required. For a change in reactive power from fully leading operation to fully lagging operation a response time of 5 seconds would be required. Once the DAR time expires, the line is restored and the voltage now recovers/exceeds the target, as the line is now re-established with additional reactive compensation.

5.37 Once again the STATCOM/SVC is required to respond with 1 to 5 seconds and restores the Q response back to its original level restoring the voltage.

5.38 The next event occurs after the reclaim time has expired and so the sequence is repeated. This occurs a third time but on the fourth occasion the event occurs within the reclaim time and on this occasion the line is locked out and can only be restored manually. DAR is automatically locked out after two events if the fault is not within the DAR time, however as the data in Table 6 shows in reality DAR events can and do occur in sequences of more than two events.

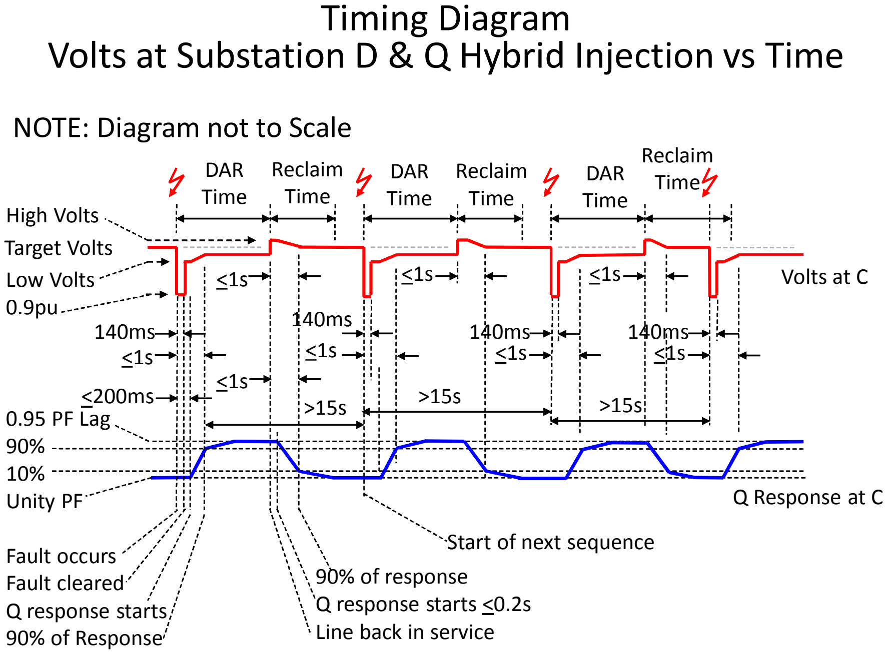


Figure 4: DAR Timing

5.39 It should be noted that other parts of Europe frequently use Single Phase High Speed Auto Reclose, which from a voltage control perspective, is less onerous as the line is brought back into service in timescales which frequently don't require Hybrid STATCOM switches to operate.

5.40 Currently there is only one circuit in Scotland which has High Speed Auto Reclose. However DAR is extensively used on the other circuits and it would prove too expensive to replace all DAR systems with High Speed Auto Reclose (see section 6).

<u>Fault Ride Through and Voltage Recovery</u>

5.41 Some Hybrid STATCOM/SVC manufacturers switch out the capacitors during a fault, further reducing reactive support. This increases the risks from voltage depression post fault and increases the risk of post fault voltage collapse and cascade tripping.

5.42 As can be seen from the diagram below, the voltage depression resulting from a fault (prior to clearance), is spread over a wide geographic area, consequently there is a risk that a large volume of reactive compensation could be lost post fault.

5.43 When this problem was initially identified, the Transmission blocking voltage (i.e. the voltage at which the capacitor was switched out) was set to a level of about 0.7pu and as this behaviour was not anticipated there was no specific requirement outlined to bring it back within short time scales.

5.44 If this approach had been adopted by a number of manufacturers, it could have affected a very wide geographic area (see example shown in Figure 5 where major areas of London and Eastern England are below 0.7pu).

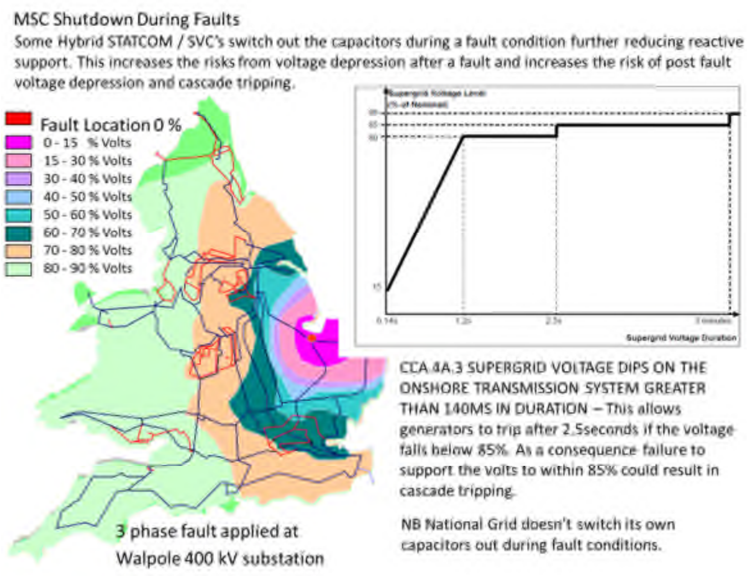


Figure 5: Voltage Depression and MSC Shutdown during Faults

5.45 The manufacturer concerned (currently National Grid are aware of only one) has worked to resolve the issue by reducing the voltage at which the capacitor switches out to 0.4pu and ensuring it switches back in service within 300ms.

5.46 Clearly, during the actual voltage depression, which could last up to 140ms, the capacitor will not have much affect but the loss of the capacitor post fault could affect the rate of post fault voltage recovery.

5.47 With only one manufacturer currently carrying out this practice, the risk is arguably low. However as a minimum, there is now a need to specify the parameters and/or behaviour for such reactive compensation devices during and after a faulted condition.

5.48 Once specified, other manufacturers may choose to work to the same parameters and switch out capacitors, which could further increase the risk in terms of post fault voltage recovery.

5.49 The manufacturer concerned acknowledges that the capacitors could be left in but believe this is unnecessarily restrictive and would increase the cost of their design. The effects on manufacturer's designs are explored later in this section.

5.50 National Grid would prefer discrete reactive elements are not switched out.

<u>Response of STACOMs and the effects of limiting reactive reserve</u>

5.51 The System Operator and Transmission Companies in GB have some concerns regarding the projected quantities of embedded and renewable generation in respect of voltage control.

5.52 Voltage support and reactive compensation from Embedded Generation is less valuable than the reactive power supplied by traditional Transmission connected generators. This is because some of the MVAr's produced by Embedded Generators are consumed by Distribution System components and step up transformers between the Distribution and Transmission Systems or are restricted by network constraints.

5.53 CC.6.3.2(c) of the Grid Code requires Power Park Modules to provide a reactive capability of 0.95 Power Factor lead to 0.95 Power Factor lag at Rated MW output at the Connection Point. Whereas traditional Synchronous Generators are required to provide continuous reactive support from 0.95PF Lead to 0.85PF Lag at the Generating Unit Terminals. Whilst this is not at the Point of Connection (POC) when step up transformers losses are taken into account the equivalent reactive capability range at the connection point is roughly similar.

5.54 Synchronous Generators however have several other advantages. First they provide short term extended reactive capability (typically a Power Factor of 0.6) when voltage is depressed due to the forcing of the DC field which drives up the internal EMF within the machine thereby producing additional reactive power to help the voltage recover.

5.55 Whilst some STATCOM's and Hybrid STATCOM's have extended capability sometimes of similar magnitude at rated voltage, it is significantly reduced at low voltage. This is especially true of devices containing Capacitors, Reactors and SVC's as the reactive current drops in proportion to voltage and the reactive power therefore drops in proportion to the square of the voltage.

5.56 Conventional Synchronous Generators do not block and will continue to produce reactive current right down to 0p.u. at the Point of Connection. The amount of current produced increases as the voltage drops, as synchronous generators generally behave as voltage source located behind an impedance.

5.57 By contrast, semiconductor sources are typically limited by the maximum current rating of the devices, so their output current remains constant. A falling voltage will result in a reducing reactive power contribution. Many designs will also shut down the electronics at voltages between 0 and 0.4pu.

5.58 Whilst none of these factors individually raise cause for concern, when coupled with the previously mentioned aspects i.e. repeatability and the fault ride through capability of the discrete reactive elements, National Grid believes there is cause for concern.

5.59 Furthermore there is a need for the System Operator and Transmission Owner to be vigilant in assessing any possible side effects resulting from the above characteristics.

Impact of Increased Switching Frequency

5.60 The Developers and Manufacturers have expressed concerns regarding the potential number of switching operations expected of mechanical reactive compensation switch elements. They are particularly concerned this may result in excessive wear, additional maintenance and potentially warrantee issues.

5.61 In response to these concerns it has been agreed a limit of 25 operations in any 24 hour period can be applied.

5.62 However there have further been requests from developers and manufacturers to additionally specify the annual number of operations expected in the Grid Code.

5.63 The new requirements relating to Repeatability and Fault Ride Through are largely driven by infrequent events such as storms, under which conditions most of the events are likely to be initiated by system faults. Consequently this idea has been rejected by the work group, as under these circumstances the transmission system equipment will be under similar duress.

5.64 The table below is published to demonstrate, the typical numbers of faults which may occur in any one year but also shows the variability, as noted by the high number of faults that occurred in 1990. For the most part 1990, predates most of the renewable asynchronous generation.

5.65 This table provides developers and manufacturers with an indication of the typical number and nature of the faults which have occurred on an annual basis. Furthermore, it highlights the potential variability and difficulties associated with publishing such figures in the Grid Code. In addition, the effects of climate change add further uncertainty and should be considered, when using past figures such as those below, to predict future requirements.

YEAR	Phase-E	2-Phase	2-Phase-E	3 & 3-Phase-E	Total
1990	746	732	53	39	**1571**
1991	153	22	4	20	**198**
1992	178	0	4	22	**204**
1993	134	19	6	26	**185**
1994	212	4	8	36	**260**
1995	110	37	8	5	**160**
1996	175	87	4	5	**272**
1997	183	14	0	7	**204**
1998	204	24	3	3	**235**
1999	174	14	4	8	**200**
2000	121	28	1	7	**158**
2001	86	78	4	1	**169**
2002	103	2	0	3	**108**
Ave. pa	**198**	**82**	**8**	**14**	**302**

Table 1: Annual Fault Figures 1990 to 2002

Response of STATCOM/SVC's and effects of Limited Reactive Reserve

5.66 The following studies were produced for the September 2013 workshop and were referenced during the Work Group. All the studies consider the effects on the contracted position in the period between 2012 and 2018 and use scenarios based on projects as proposed in 2012/13. Whilst some of the study conditions might be considered worse case, they are believed to be credible and consider conditions in the near future with relatively low penetration of asynchronous generation.

5.67 The MW and MVAr rating of the projects are realistic. However the equipment at the sites has been replaced by generic equipment which meets the minimum Grid Code requirements as it's been interpreted without repeatable performance. The studies are therefore illustrative and not a reflection of actual Generator performance.

5.68 The studies were performed on and using the 2012 MVA ratings of the following sites:

- Spalding North, Bicker Fen, Walpole Single Circuit Trip / DAR
- Southern Coastal Region (Rampion, London Array and Thanet) – Voltage Collapse
- Hedon Multiple Circuit Trips and DAR's

Spalding North, Bicker Fen Walpole Circuit Trip / DAR Operation

5.69 This study considers the connection of a proposed Wind farm at Mumby. The reinforcements, system model and wind farm MW and MVAr rating are as per the contracted position.

5.70 The study demonstrates the effect of tripping one circuit, consisting of lines A65Y, A660 and A65W.

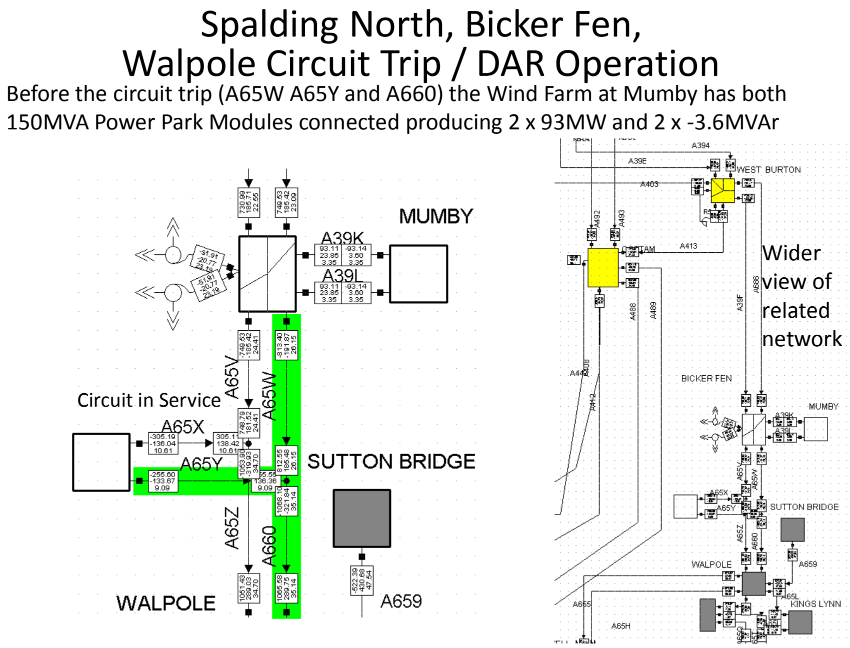


Figure 6: Spalding North, Bicker Fen & Walpole Study

5.71 After the trip of the circuit containing lines A65Y, A65W and A660, Mumby incurs a 41.3MVAr swing on an SVC rating of 49.34MVAr (or 83.7% of Rated Capacity of each Power Park Module). This results in capacitor and / or reactor switching depending on the Hybrid SVC / STATCOM configuration and the voltage set point.

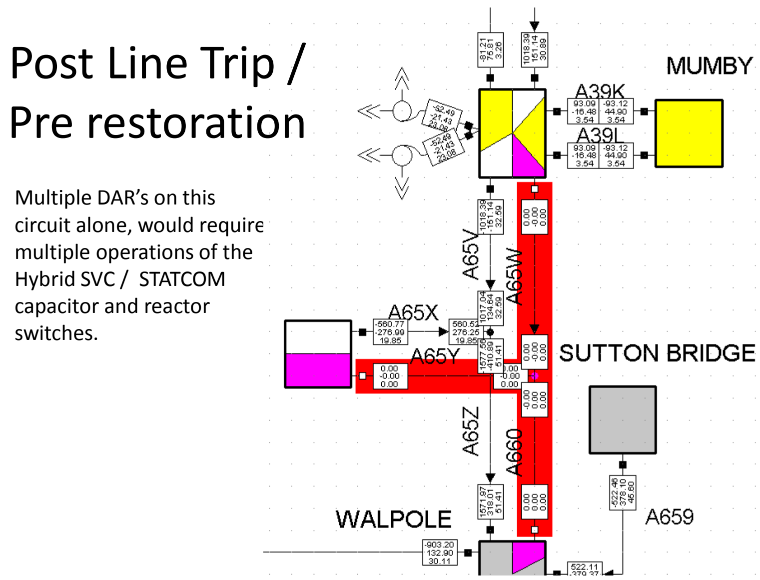


Figure 7:Spalding North, Bicker Fen & Walpole Study after Trip

Voltage Collapse on the South Coast

5.72 This study considers the effect of limited reactive reserves on the south coast using wind farms located at or near Bolney (Rampion), Cleve Hill (London Array) and Canterbury North (Thanet, which is embedded). The wind farm data was replaced with generic data to protect the integrity of the owners and is not meant to be representative of their actual performance.

5.73 All synchronous generators from Kemsley to Lovedean are shut down and the south coast is therefore highly dependent on voltage control from the asynchronous generation, which represents about 40% of the available support in this area.

5.74 In this scenario it is assumed all three wind farms have Hybrid STATCOM's who provide 66% of their reactive power from Capacitors and Reactors and as a result of multiple lightning strikes in the area these devices are now inoperable for a period.

5.75 It is assumed, NGET Market Operations have performed studies and set the system up to cover for double circuit faults. However a double circuit fault occurs at Kemsley and within a few seconds generators start to trip in timescales which are too fast for NGET to take evasive action. This ultimately leads to voltage collapse and disconnection of load.

5.76 The following graphs show the effect on system voltage with the wind farm providing an inappropriate response and as described above where there is load disconnection due to voltage collapse (see Figure 8).

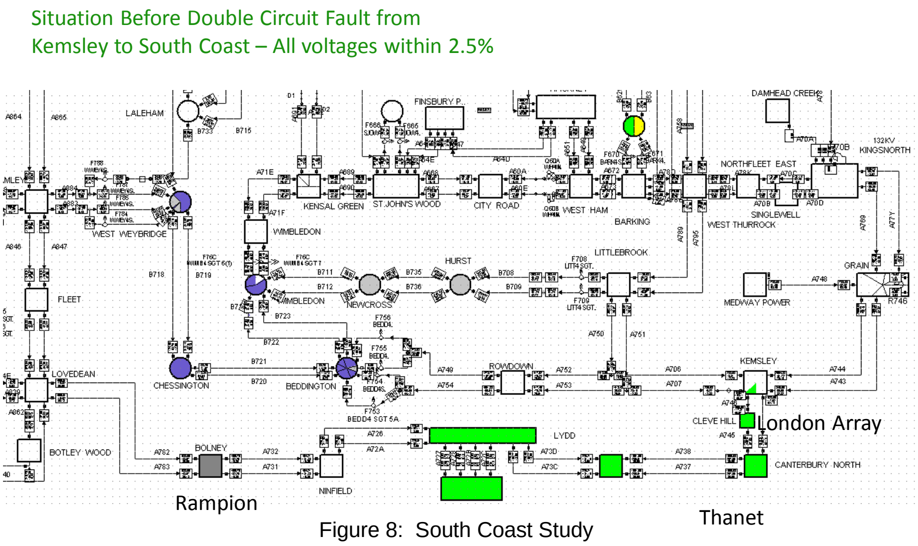


Figure 8: South Coast Study

5.77 Had full reactive reserve been provided, the voltage is maintained within limits and load disconnection is not necessary (see Figure10).

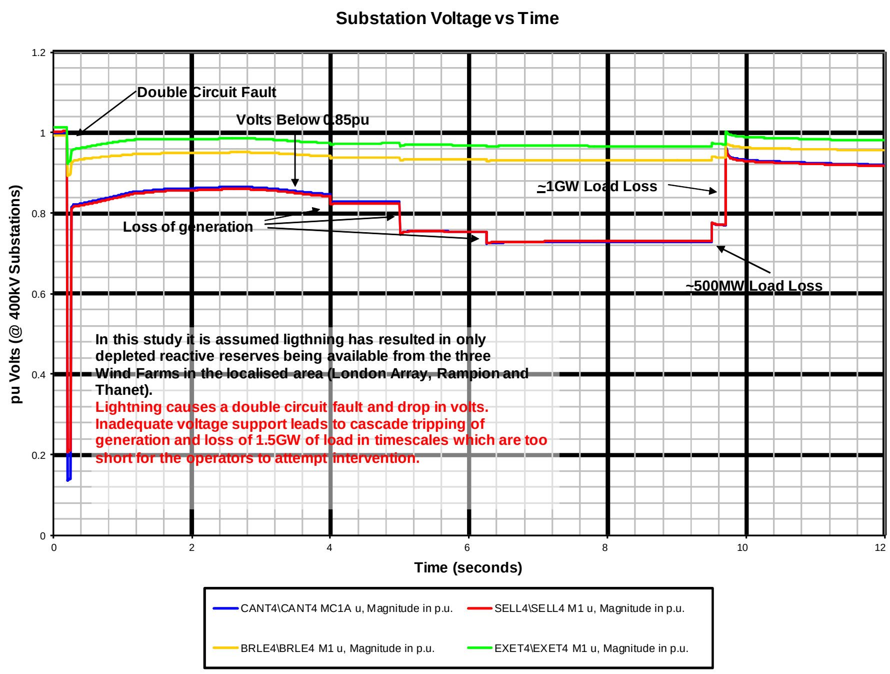


Figure 9: South Coast Study with Limited Reactive Reserve

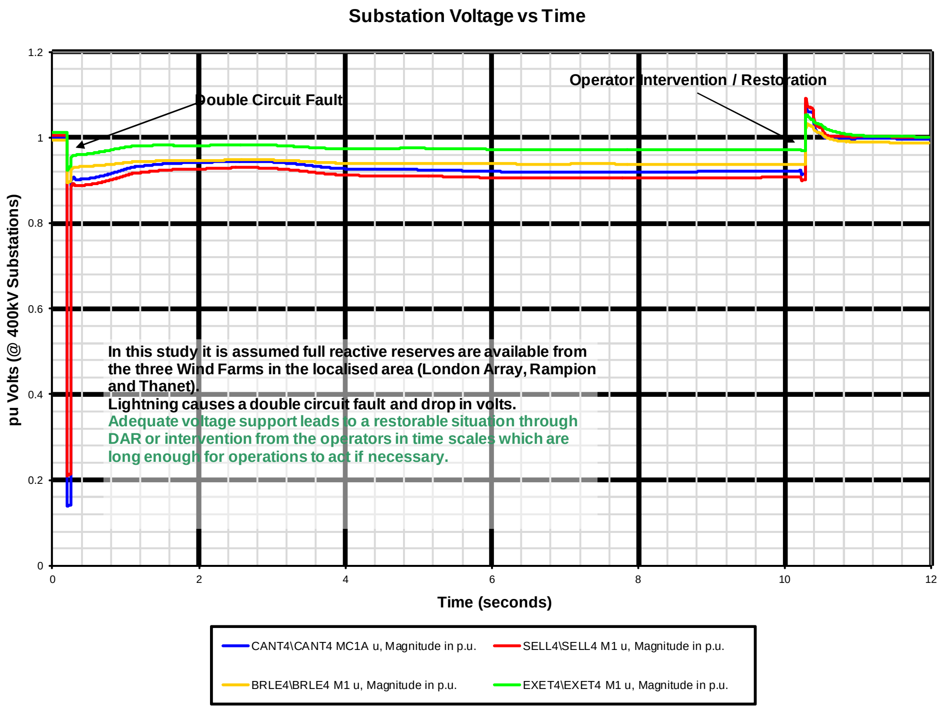


Figure 10: South Coast Study with Full Reactive Reserve

<u>Multiple Trips on Different Circuits</u>

5.78 This study considers the effect of multiple trips on different circuits but in the same locality. The trips, which are located in the Saltend area results in DAR's on lines B38G, B38C, B389 and B38H.

5.79 As a result the 400MVA of Wind Generation connected at Hedon, is capable of providing 124.9MVAr of reactive power and hence voltage support.

5.80 For the pre fault condition the Wind Farm produces -31MVAr and 200MW. As various circuits trip, the Wind Farm reactive output responds as follows:

- No Trips => -31MVAr
- B38G => -63.16MVAr
- B38H => +47.9MVAr
- B389 => -68.42MVAr
- B38C => -60.05MVAr
- B389 & B38H => +72.2MVAr

5.81 Capacitor and reactor switching is likely. Furthermore changes in the model configuration relating to demand, weather conditions, configuration, connection and output of conventional generation (in this case at Salt End) and operational parameters such as transformer tap selection and wind farm voltage set points will further complicate the picture producing differing requirements from the Wind Farm.

5.82 These variables change throughout any given day at hundreds of points throughout the system and model. From an operational perspective additional considerations relating to limited reactive reserve are obviously undesirable.

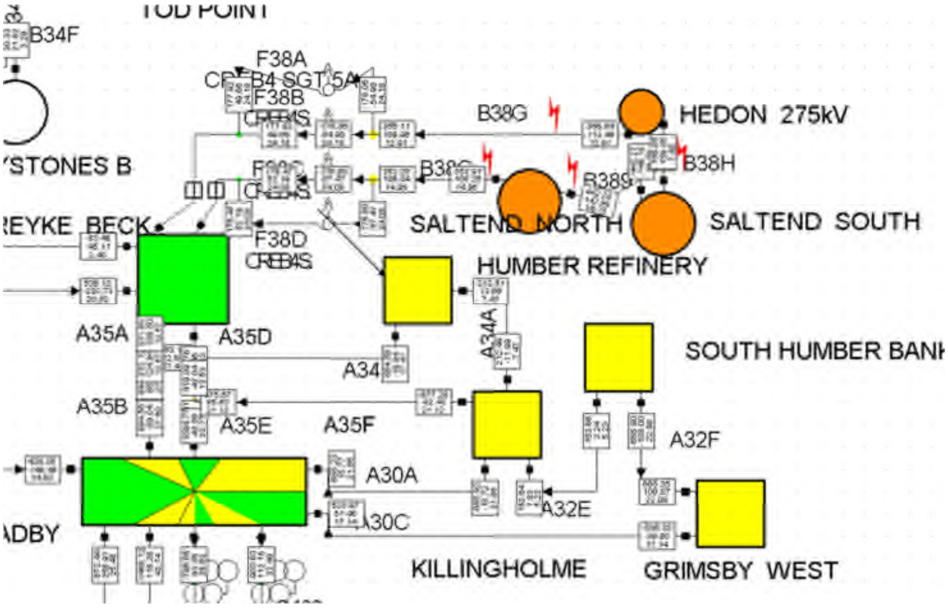


Figure 11: Heddon Study

Lightning Storm Data

5.83 The following section relates to lightning data recorded during the period 2001 to 2006. This period was chosen as the data is relatively recent, readily available and in an appropriate format. It identifies the frequency and location of lightning in England and Wales and the most likely times of day and year when lightning will strike. The final subsection summaries some of the significant events reported by the control room.

5.84 The data was compiled using equipment which logs the time and position from detection of the electromagnetic disturbance resulting from a lightning strike. The position is calculated through triangulation.

5.85 The table below shows the total number of lightning strikes throughout the six year period for 'England & Wales' and the 'UK & Ireland'.

	2001	2002	2003	2004	2005	2006
England & Wales	146880	86702	74753	100095	148806	143618
UK & Ireland	168708	98482	98332	122497	158321	157796

Table 2: GB Lightning Events 2001 – 2006

5.86 Whilst the majority of strikes will not hit the Transmission System, the Transmission System is a prime target and can take a significant number of hits during a storm. The effects of a strike and subsequent fault / short circuit results in a measurable disturbance across a large proportion of the system.

5.87 The graphs below show the frequency of strikes in relation to time of day and time of year for the six years in question. Whilst the data shows that strikes can occur at any time, it also clearly shows there is a significantly higher risk in the afternoon and during the summer.

5.88 This correlates with the control room reports of significant lightning events (see Table 2).

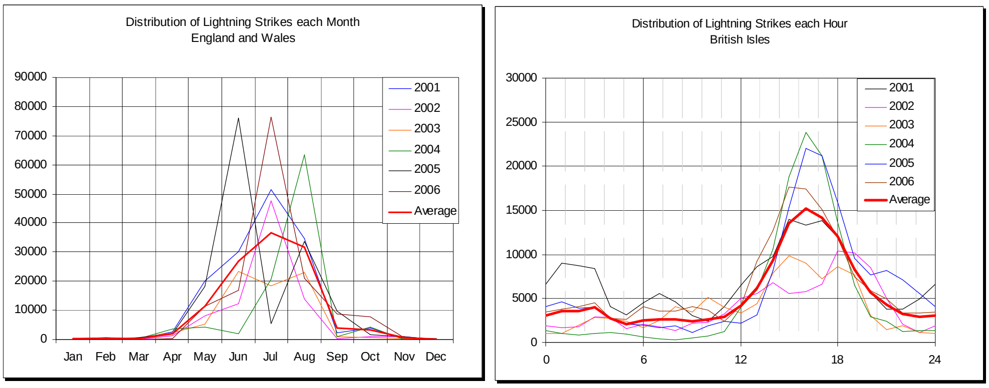
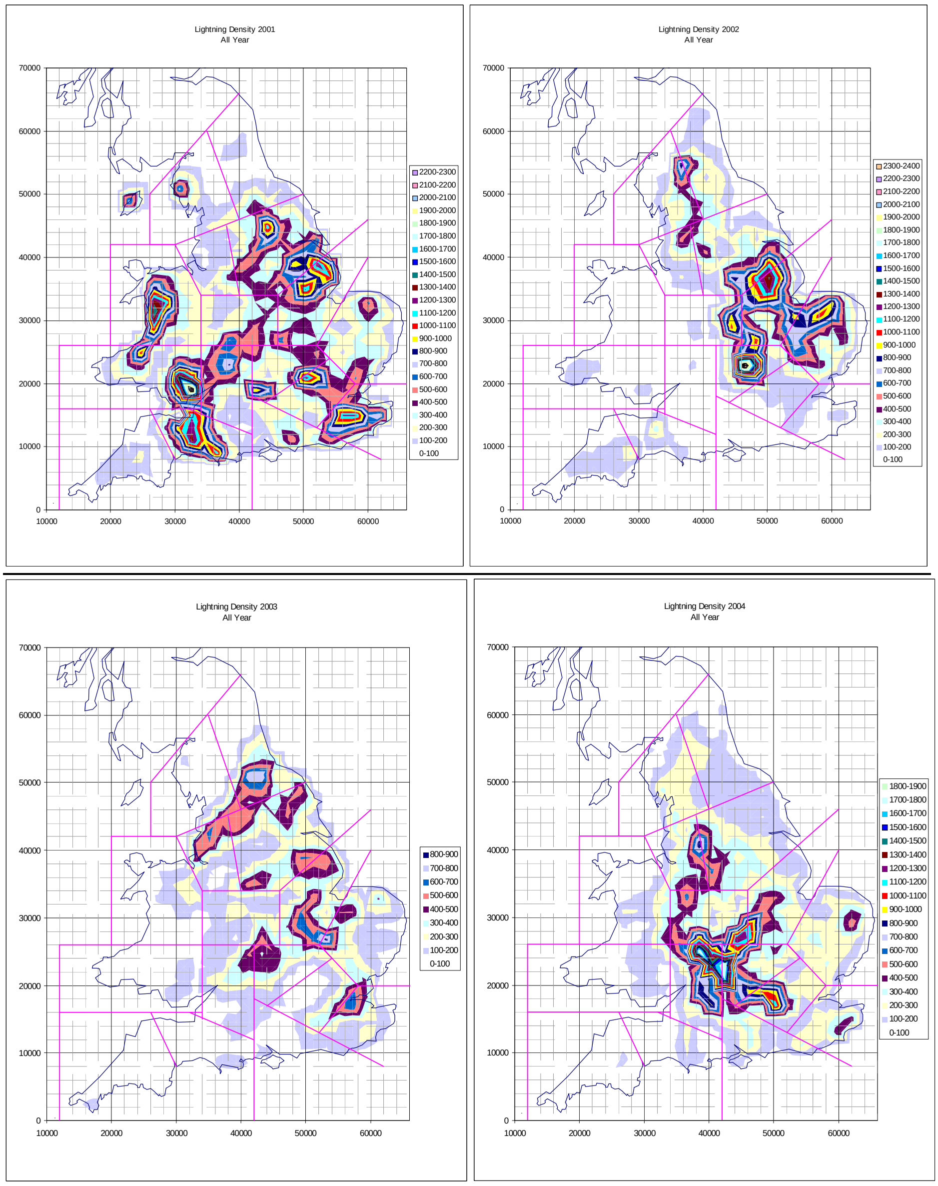


Figure 12: Frequency of Lightning vs Time of Year and Day

5.89 The maps shown in Figure 13 below, show the frequency of strikes against specific areas for the six year period. Unlike chronological records, the picture is less clear as year on year different areas of the country are hit at different frequencies.

5.90 From this and the fact that the effects of a strike cover a wide geographic area, it is concluded that there is no specific areas which can be identified as problematic. Any requirements in relation to lightning should therefore be applied globally.



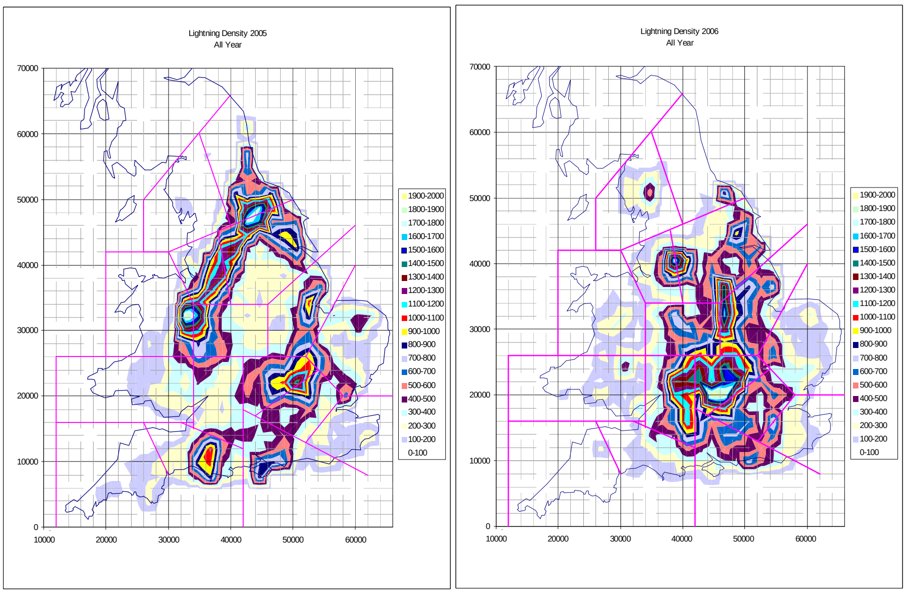
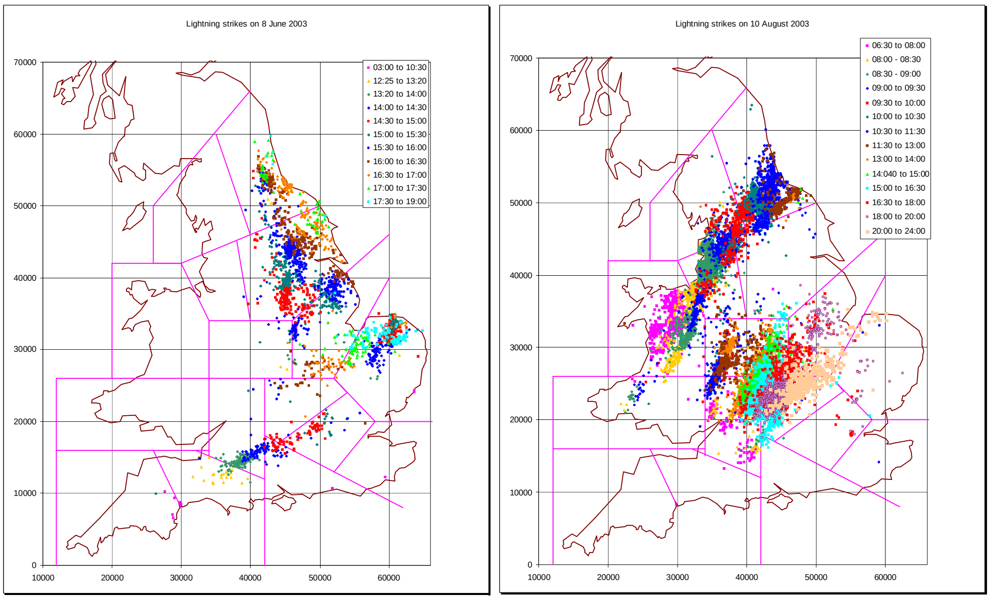


Figure 13: Frequency of Lightning vs Location 2001 – 2006

5.91 The information in Figure 14 details four lightning storms on four days during June and August 2003. It shows where the lightning strikes occurred during each hour of the day. The results show that on the different days, different areas were affected and over the four day period, most of England and Wales is affected to varying degrees with relatively few areas unaffected. In addition, for the different hours, the strikes were concentrated in specific areas, increasing the likely hood of multiple localised strikes.

5.92 Furthermore from the previous data, areas such as Cornwall and some areas of the south coast appeared to be at low risk but in this data we now see evidence of the risk in these regions too. Consequently, this reinforces the need for a system wide requirement.



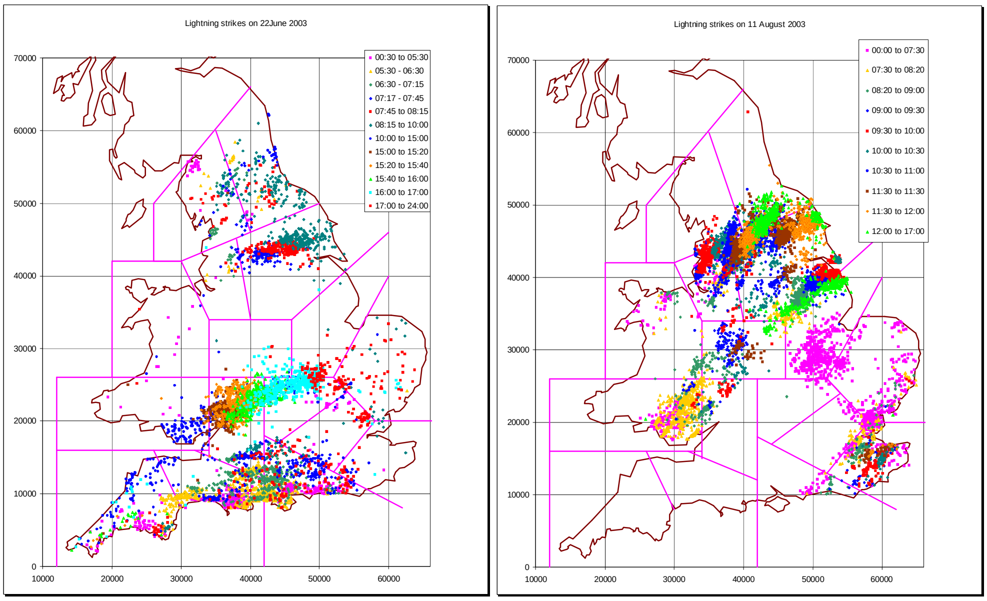


Figure 14: Location of Lightning Strikes for Specific Hours of the Day on 8 June 2003, 10 August 2003, 22 June 2003 and 11 August 2003

5.93 The following are examples of typical lightning events as recorded by National Grid's control room staff. These events generally take place in the summer and as mentioned earlier show a direct correlation between the data sources.

5.94 The events are recorded manually and so rely on human interpretation as to which factors were important and therefore recorded. It should be noted that, not all the events maybe recorded in sequences where the situation is rapidly changing or where they were considered secondary or unimportant.

Date	Event Type	Description Summary
Tue 3 Aug 2004	Lightning	6 Circuit Trips (5 DAR Restoration's) in 3.25Hrs.
Wed 18 Aug 2004	Lightning	10 Circuit Trips in 5 Hours including **3 DAR restorations in 3mins.**
Wed 31 Aug 2005	Lightning	11 Trips in 2hrs 21mins including **6 in 27minutes** in the same area. All recovered by DAR.
Fri 15 Jun 2006	Lightning	9 trips in 3 hours, several within a few minutes of each other.
Sun 2 Jul 2006	Lightning	8 trips in approx. 1.5 hours including **4 trips in 17minutes and 2 trips in 2mins**.
Wed 11 Oct 2006	Lightning	6 trips in approx. 6 hours in the Taunton area.
Sun 1 Jul 2007	Lightning	**5 trips in a localised area in 1/2 hour 4 of which auto reclosed or where restored manually**.
Wed 1 Jul 2009	Lightning	4 trips/events over a period of 25 minutes
Mon 15 Jun 2009	Lightning	8 trips and restorations (i.e. 16 in total) in 3 hours including **4 in London area in 27 minutes**.
Thu 28 Jun 2012	Lightning	9 trips at various places in GB. At about 1 hour or half hour intervals

Table 3: Summary of Significant Lightning Events 2004 – 2012

Future Operational Scenarios

5.95 The risk as presented by the Transmission Owners and System Operator has to date been contained and this might be used as an argument for not making any changes. However TO's and the SO are concerned in relation to the future which predicts a significant growth in the volume of asynchronous generation.

5.96 If consideration is given to the Gone Green and Slow Progression energy scenarios for 2025/2026 and this is compared with the summer minimum demand profile (see

Figures 15 to 17 below), we see renewables (mainly wind) and Nuclear are considerably greater than the summer minimum demand.

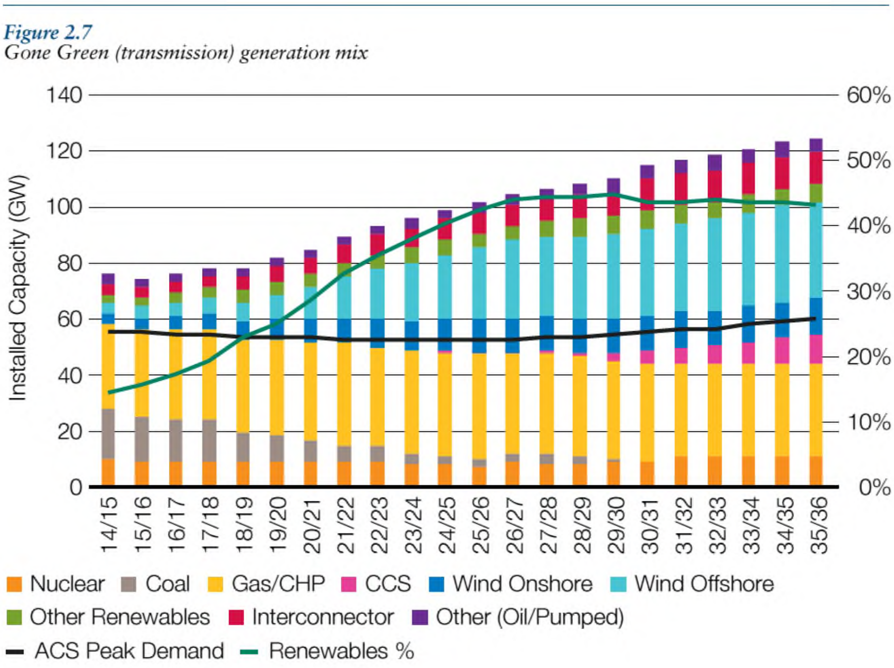


Figure 15: Gone Green (Transmission) Generation Mix (Source 2014 FES)

5.97 The figures quoted are forecasted information based on the best available data at the time of publication. These figures may therefore be pessimistic but equally could underestimate the amount of renewable generation connecting in the future.

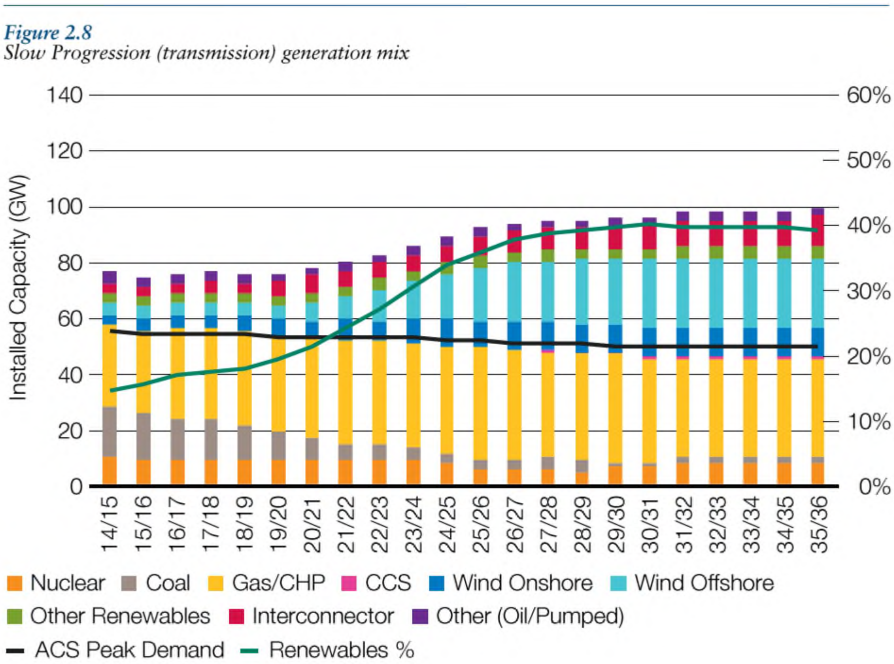


Figure 16: Slow Progression (Transmission) Generation Mix (Source 2014 FES)

5.98 Assuming these predictions are credible then it is conceivable that during the summer, the generation could comprise largely of large Nuclear Stations with Asynchronous Generation providing significant proportions of voltage support.

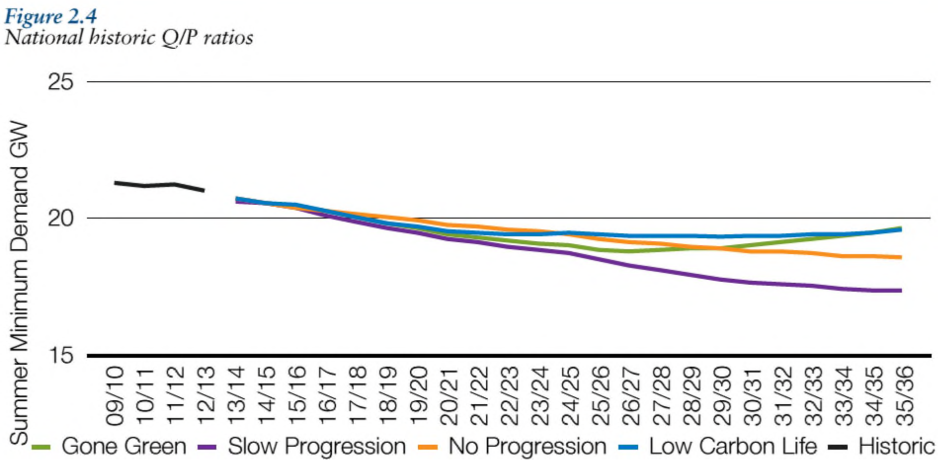


Figure 17: Summer Minimum Demand (Source 2014 FES)

5.99 All of these conditions coincide with the summer minimum which also correlates to the maximum frequency of multiple lightning strikes.

Winter Storm Data

5.100 The SO and TOs keep records of past severe weather events. These systems comprise of system wide data logging, individual discrete loggers at specific locations and operational accounts of the events, consequences and counter measures.

5.101 National Grid is in the process of updating its global data logging system which typically records to a resolution of 1 minute. Scottish Power has recently installed a new data logging system and was able to present recorded data to the Work Group with a resolution of 1 second.

5.102 Operational accounts of severe weather events stretch back decades and for this reason are very valuable. However it is clear when comparing these with the machine recorded data that the author's interpretation as recorded from an operational log sheet plays a key part in the information that is recorded.

5.103 Whilst the author's interpretation can be very valuable it may also omit information that was considered irrelevant at the time but might be relevant when considering future scenarios. This is evident when comparing the event logs from the Scottish system with the Control Room reports. For the three cases presented below, only one included a sequence of faults from a data logger.

5.104 The worst UK Storms normally occur in the winter or occasionally autumn (e.g. October) and spring (e.g. March). The most common problems are caused by conductor clashing but the situation can be complicated by other factors such as flooding.

5.105 Whilst some Wind Generators may be shut down, it is conceivable some may be operational or provide reactive services, as may other forms of asynchronous generation (e.g. solar, variable speed hydro, tidal). Furthermore HVDC interconnectors and OFTO networks should still be operational and may use Hybrid STATCOM's / SVC's.

5.106 For all of the above reasons and in the interest of fairness, simplicity and economy of scale, the TO's and SO believe it is desirable to have a single requirement that covers all generation types.

5.107 The three storms considered and analysed were:

- Scotland – 5 December 2013
- Scotland – 3 January 2012
- England – 23 and 24 December 2013

5.108 Part of a typical sequence of events from the data logging system is shown in Table 4. The list comprises of an event description and time and data when it occurred.

5.109 The event lists provided were analysed to determine the frequency of the events. The elapsed time between events was of particular interest.

5.110 The results were published in two forms. Figure 18 is a graph showing the total number of events which would be covered for specific repetition capability. It has four plots, one for each of the storms listed above and one for the aggregation of all the results.

5.111 The graphs show the percentage readiness for the events which occurred, verses repeat response capability of the device. It's acknowledged that events may or may not require a response. This partially explains the reason 25 responses limit is less than the total number of events.

5.112 The time on the x axis, is the elapsed time in seconds before the STATCOM/SVC is ready to respond i.e. the time we are trying to determine. The y axis is the proportion of switching events the STATCOM/SVC would have been ready to respond to.

5.113 The English data appears to be more favourable but this is because it is recoded to a resolution of 1 minute and additional events which occur at the same time are ignored, the results are therefore optimistic for intervals of 1 minute or less.

5.114 The results show that for a STATCOM or SVC which can operate repeatedly every 15 seconds, about 96% of the events are covered. If the performance is improved to 5 seconds, over 98% of the events are covered. Likewise for 30seconds typically 85% of the events are guaranteed but for one of the storms, the result was only 80% at 30seconds.

Event	Time	Notes	Events <1 min	Time Diff.	Elapsed Seconds
Dounreay – Thurso – Mybster – Dunbeath – Brora – Shin (UTS) 132kV cct	05:14:00		1	00:00:00	0
Dounreay – Thurso – Mybster Shin (UTN)	05:14:00		2	00:00:00	0
Fort Augustus – Broadford 132 kV cct	05:58:00		1	00:44:00	0
Sloy – Inveraray (ISW)	06:06:34	Red	1	00:08:34	0
Peterhead – Blackhillock 275kV cct (VH)	06:14:00		1	00:07:26	0
Blackhillock – Keith 275kV cct (HK1)	06:14:00		2	00:00:00	0
Keith – Kintore 276kV cct (XK)	06:14:15	R-Y	3	00:00:15	15
Inverary – Ardkinglas – Sloy – Inverarnan 132kV cct (SN1/KS1/IK1)	06:14:32	Yellow	4	00:00:17	32
Inverary – Ardkinglas – Sloy – Inverarnan 132kV cct (SN1/KS1/IK1)	07:03:03	Blue	1	00:48:31	0
Inverary – Ardkinglas – Sloy – Inverarnan 132kV cct (SN1/KS1/IK1)	07:17:21	Yellow	1	00:14:18	0
Sloy – Windyhill – Dunoon – Whistlefield East 1 132kV cct (SWE1/GL1)	07:27:11	Red then R-Y	1	00:09:50	0
Hunterston – Kilmarnock South 400kV cct	07:28:42	Yellow	1	00:01:31	0
Kilwinning – Meadowhead 2 132kV	07:28:53	Red	2	00:00:11	11
Sloy – Windyhill – Dunoon – Whistlefield East 1 132kV cct (SWE1/GL1)	07:29:24	Yellow	3	00:00:31	42
Sloy – Windyhill – Dunoon – Whistlefield East 1 132kV cct	07:29:50	Yellow	4	00:00:26	68

Event	Time	Notes	Events <1 min	Time Diff.	Elapsed Seconds
(SWE1/GL1)					
Kilwinning – Meadowhead 2 132kV	07:33:30	Red	1	00:03:40	0
Inverkip - Strathaven 400kV cct	07:38:01	Blue	1	00:04:31	0
Coalburn Strarhaven 400kV cct	07:40:04	Red	1	00:02:03	0
Hunterston – Kilmarnock South 400kV cct	07:43:01	Yellow	1	00:02:57	0

Table 4: Typical Sequence of Events from Data Logging System

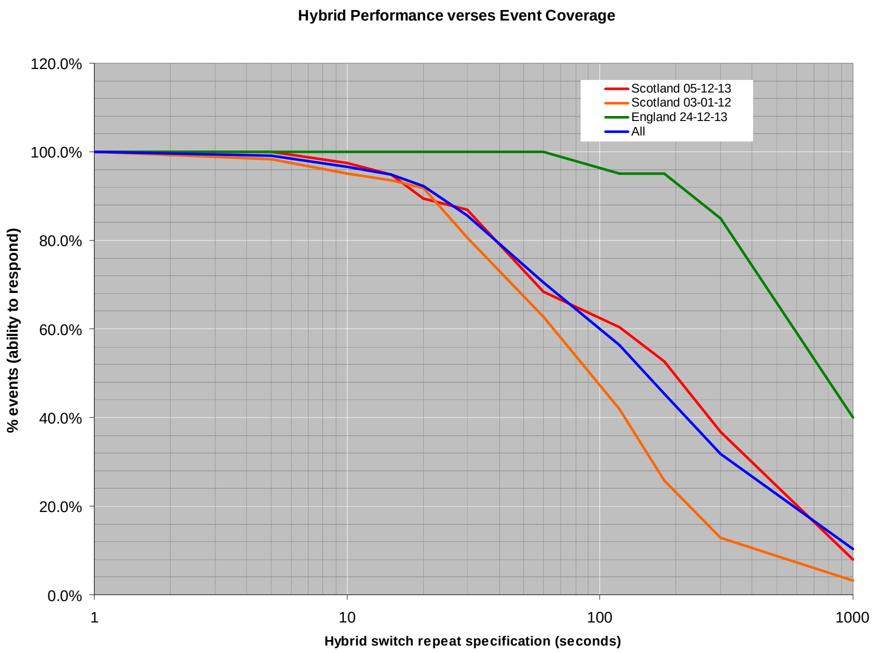


Figure 18: STATCOM / SVC repeat Performance Capability vs Events Covered

5.115 Table 5 summarises the data from the three storms by listing:

- The number of total events (Total Events)
- The total duration of all the events (Total Duration of all Events)
- The average time between events (Average Interval)
- The maximum number of event sequences where each event in the sequence occurs one minute or less after the previous event (Total event clusters where events are less than one minute apart)
- The maximum number of event sequences where at least 4 events occur less than or equal to 1 minute apart (Total event clusters where >4 events occur are one minute or less apart)
- The maximum length of an event sequence where at least 4 events occur less than or equal to 1 minute apart (Maximum Length of Cluster)
- The average duration of an event sequence where at least 4 events occur less than or equal to 1 minute apart (Average Duration of 4 Event Cluster)

- The shortest time between events ignoring events which occur at the same time i.e. same second for the Scottish data or same minute for the English data (Shortest time between events)

5.116 The Scottish data shows event sequences of 67 events over a period of 3 hours. During this time 5 event clusters occurred where the cluster length was greater than or equal to 4 events with an average elapsed time between events of about 22 seconds.

Scotland 5 December 2013	**Quantity**	**Units**
Total Events	41	Events
Total Duration	4	Hours
Average Interval	5.85	Minutes
Total event clusters where events are less than one minute apart	8	Clusters
Total event clusters where ≥4 events occur are one minute or less apart	4	Clusters
Maximum Length of Cluster	4	Events
Average Duration of 4 Event Cluster	79	Seconds
Shortest time between events	11	Seconds
Scotland 3 January 2012	**Quantity**	**Units**
Total Events	67	Events
Total Duration all Events	3	Hours
Average Interval	2.69	Minutes
Total event clusters where events are less than one minute apart	14	Clusters
Total event clusters where ≥4 events occur are one minute or less apart	5	Clusters
Maximum Length of Cluster	5	Events
Average Duration of 4 Event Cluster	66.4	Seconds
Shortest time between events	4	Seconds
England 23-24 December 2013	**Quantity**	**Units**
Total Events	20	Events
Total Duration	4.5	Hours
Average Interval	13.50	Minutes
Total event clusters where events are less than one minute apart	1	Clusters
Total event clusters where ≥4 occur are less than one minute apart	0	Clusters
Maximum Length of Cluster	2	Events
Average Duration of 4 Event Cluster	N/A	Seconds
Shortest time between events	60*	Seconds

Table 5: Summary of Event Data for Three Example Storms

5.117 Table 6 provides a summary of some the significant weather events. This is not a complete list just a sample.

5.118 Prior to 1997 only paper records exist.

Date	Event Type	Description Summary
Burns Day Storm 1990	**Storm**	**261 trips 80 faulted circuits in 24hours**.
Wed Thur 24/25 Dec 1997	**Storm**	**33 circuits tripped in 5 Hours**
Sat 26 Dec 1998	**High Winds**	**Approx. 20 trips, including 4 DAR restorations on same line in 4mins**.
Tue 27 Feb 2001	**Snow & High Winds**	**Multiple trips on Scot. Interconnector. 600MW generation lost**.

Sat 8 Jan 2005	**Gales**	**32 faults on the NG System including 6 in 18, 7 in 21, 5 in 22 and 5 in 24mins**, most of which were restored by DAR
Thur 18 Jan 2007	**137 Protection Operations**	**51 DAR Sequences** – 3 Conductor Failures resulting in permanent loss of circuits. A further 14 trips in 4 hours including sequences of **4 trips in 40mins, 4 trips in 8mins, and 3 trips in 10mins**. Most restored by DAR.
Tue 3 Jan 2012	**Severe Weather**	Over 50 Circuit Trips listed including event log.
Thur 5 Dec 2013	**High Winds**	**Multiple Circuit Trips** – 5 Circuits left of service, 10MW of customer disconnection.
Mon 23 Dec 2013	**High Winds**	Details approximately 17 circuit trips.

Table 6: Summary of data for some significant Winter Weather Events

Consistency with the European ENTSO-E Requirements for Generators Code

5.119 A joint Grid Code / Distribution Code Workgroup (GC0048) are currently aiming to modify the GB Grid Code to make it compliant with the ENTSOe's RfG (Requirements for Generators).

5.120 In order to promote cross border trading requirements are needed. TO's and SO's may specify additional or existing requirements but they must be compliant and compatible with RfG. RfG was therefore discussed within the Hybrid STATCOM / SVC workgroup to ensure compliance.

5.121 The relevant section of RfG (in relation to STATCOM's and SVC's, Article 21 (3) (d), is extracted below. When considering repeatability paragraph (iv) (shown in italics) and particularly the wording shown in bold italics, are most relevant and provoked the most debate.

(a) with regard to reactive power control modes:

(i) the power park module shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode;

(ii) for the purposes of voltage control mode, the power park module shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a setpoint voltage covering at least 0.95 to 1.05 pu in steps no greater than 0.01 pu, with a slope having a range of at least 2 to 7 % in steps no greater than 0.5 %. The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint;

(iii) the setpoint may be operated with or without a deadband selectable in a range from zero to +-5 % of nominal network voltage in steps no greater than 0.5 %;

(iv) *following a step change in voltage, the power park module shall be capable of achieving 90 % of the change in reactive power output within a time t_1 to be specified by the relevant system operator in the range of 1 to 5 seconds, and must settle at the value specified by the operating slope within a time t_2 to be specified by the relevant system operator in the range of 5 to 60 seconds,* ***with a steady-state reactive tolerance no greater than 5 % of the maximum reactive power.*** *The relevant system operator shall specify the time specifications;*

(v) for the purpose of reactive power control mode…

(vi) for the purpose of power factor control mode…

(vii) the relevant system operator, in coordination with the relevant TSO and with the power park module owner, shall specify which of the above three reactive power control mode options and associated setpoints is to apply, and what further equipment is needed to make the adjustment of the relevant setpoint operable remotely;

[Note: Items (v) and (vi) not fully listed as only Voltage Control mode is applicable in GB.]

5.122 There was considerable debate in relation to Article 21 (3)(d)(a)(iv) which specifies the response times t1 (1 - 5secs) and t2 (5- 60s) in relation to a step change in voltage. The debate particularly focused on the last line states that the steady state error should be no greater than 5%.

5.123 As no other times were specified it was argued that a reader might interpret the text in one of the three ways with regard to repeatability:

1. A response of 90% of the change should always be delivered within t1

2. Steady state is only achieved after t2 and the output should always be within 5% when t2 expires

3. RfG was never intended to specify repeatability and is therefore irrelevant

5.124 Interpretation 1 was initially presented to the workgroup. It was suggested that equipment should be capable of a repeatable performance on a 5 second basis to ensure compliance with RfG. There was considerable resistance to this idea with a number of Workgroup Members stating they didn't believe RfG intended to specify repeatability requirements.

5.125 After further discussion within National Grid, position 2 was presented. This received less resistance but there were still objections from other members of the Workgroup.

5.126 Mechanical switches have a limited lifetime which is typically measured in terms of the number of switch operations (typical figures quoted are 10,000 and 100,000 operations). Manufacturers were concerned that enabling the switches to operate freely and frequently in response to voltage changes, might result in very frequent switching. This could then result in excessive ware and high maintenance costs.

5.127 To overcome these concerns it was initially proposed an alarm could be triggered if an excessive number of operations occurred within any 24 hour period. The generator could then contact the control room and request the switches are locked open or closed.

5.128 Large fluctuations in voltage or reactive power are clearly not desirable and under normal circumstances the SO and TOs would work to minimise these. Consequently from the SO and TO perspective this was not seen to be a major problem and the proposed alarm and dialog seemed to provide a sensible method of resolving excessive switching operations.

5.129 Some manufacturers however were still concerned about this. They pointed out that once the equipment was installed, control of it was passed to the generators. It was felt that the manufacturer's inability to limit the number of switching operations might present too big a risk and force them to withdraw Hybrid options.

5.130 Consequently the storm data was revisited and Scottish Power and the National Grid control room staff consulted. It was decided that limiting the number of operations to 25 events was acceptable provided the generator immediately informed the control room of the reduced reactive capability.

With regard to RfG, unless subsequently changed during the implementation process, the workgroup is taking the position that the Grid Code changes recommended in this document are consistent with RfG.

Manufacturers' Survey

5.132 The workgroups objective was to specify requirements which met the needs of the Transmission System, was technically feasible and was acceptable from a cost perspective.

5.133 It is clear that Hybrid STATCOM's and SVC's offer significant cost benefits compared to Full STATCOM's and SVC's but these needed to be balanced with concerns over security of supply. Furthermore, manufacturers and developers regard ambiguous Grid Code requirements as a significant financial risk.

5.134 As discussed in the previous sections, clarification of the repeatability requirements largely protects against infrequent event sequences during which generation may or may not be operational.

5.135 Furthermore from Figure 5.99.1 there is a question of where to draw the line in terms of the repeat capability time i.e. dead time after which the equipment must be ready to respond. Consequently this subject raised significant interest and debate.

5.136 It was initially proposed that this time should be 5 seconds however over the period the work group, this was relaxed to 15 seconds. Whilst evidence was found that 1-5 seconds is achievable with mechanical switches, 15 seconds was chosen for the following reasons:

1. 15 seconds covers about 96% of the events (see figure 5.99.1) and 5 seconds only improves the situation to 98%

2. National Grid and the Scottish TO considered the decision acceptable as it is compatible with DAR time scales and storm data.

3. There are a wider range of switches available

4. Existing equipment is already required to meet two operations at 15 second intervals

5.137 Various manufacturers were questioned and surveyed at different times throughout the working group process, to determine the requirements were technically feasible and to determine the cost implications.

5.138 During the workgroup meetings a number of concerns were raised regarding communications and repeat capability performance of DFIG's. However after further conversations with manufacturers and the compliance teams, these were largely discounted and the focus turned to Hybrid devices themselves.

5.139 Six Hybrid STATCOM / SVC manufacturers were questioned about their equipment's capability to the meet requirement as detailed in Table 5.131.1.

5.140 In particular they were asked whether there current equipment meets the new requirement for repeatability and FRT and that in the event that the equipment does not meet the requirement, they were asked about the cost and timing implications of meeting these requirements. The results are published in Table 5.131.1.

5.141 In the interest of confidentiality, the names of the manufacturers have been omitted. At the time of the survey the manufacturers were aware of and responding to the draft legal text presented in section 0 Annex 3 - Proposed Legal Text. All of the manufacturers are offering Hybrids or a variety of solutions, as we understand the answers, 5 of them specifically relate to Hybrids.

Manufacturer	**Compliant with new repeatability Requirement**	**% Unit cost if not compliant**	**Availability**	**Compliant with new FRT requirement**	**% Unit cost if not compliant**	**Availability**
A	Current design meets proposed change	0%	Now	Current design meets proposed change or Blocks at 0.4pu (Both Available Now)	0.5%	Now
B	Current design meets proposed change	0%	Now	Current design meets proposed change	0%	Now
C	Current design meets proposed change	0%	Now	Current design meets proposed change	0%	Now

Manufacturer	Compliant with new repeatability Requirement	% Unit cost if not compliant	Availability	Compliant with new FRT requirement	% Unit cost if not compliant	Availability
D	Proposed change is feasible	0%	Now	Current design meets proposed change	0%	Now
E	Proposed change is feasible	-13% to +7% *	12 Mths	Current design meets proposed change	0%	Now
F	Current design meets proposed change	0%	Now	No Answer – still investigating.	-	-

* -13% to +7% depends on equipment rating. Clarification of the requirement has in this case leads to cost decreases for some equipment ratings and increases for others.

Table 7: Survey of Manufacturers

6 Cost Benefit Analysis

6.1 This section considers the cost benefit analysis of various solutions including:

- Network Options
- Transmission Owner Provides Reactive Compensation
- High Speed Auto Reclose
- Manufacturing Options
- Full Convertor
- Hybrid STATCOM / SVC with Improved Performance

Transmission Owners Provide reactive Compensation

6.2 Requiring the Transmission Owner and not the Generator to provide the reactive power, has some advantages and some disadvantages.

6.3 On the positive side the Transmission Owner has some flexibility to locate compensation where it is most required. Also, from the Transmission Owner's perspective, they will be funded for efficient investment. They may also choose to extend the assets capability, by for example adding Power Oscillation Damping.

6.4 However there are significant disadvantages to. The following issues have been identified:

- Reduced competition and diversity as the Transmission Owner would be the main provider in a given geographic area.

- The requirement for compensation is usually driven by active power flow, such as where a generator connects to the network, which in practice limits the Transmission Owners options.

- Many Power Park Modules have an inherent reactive capability which might be wasted if they are not required to provide support. It may also be cheaper for the generator to provide the reactive compensation, as they may only need to provide an additional supplement to the existing capacity, whereas the Transmission owner would need to provide assets capable of supplying the full reactive capability as a separate development.

- It is likely that some reactive compensation will always be required by the Generator and this would only result in a reduction in the requirement, with further supplementary compensation provided by the Transmission Owner. For solutions which rely on Hybrid STATCOMs, developers may find the reduction of convertor size is not possible and consequently they will only be able to remove the cheaper static elements and not the more expensive electronic components.

6.5 The figures given below show typical costs from developers and Transmission Owners for providing 30MVAr of installed and commissioned Reactive Compensation at the point of connection to the Transmission System. These costs demonstrate the previously mentioned factors e.g. some of the reactive power may be provided at no extra cost by the Wind Turbines.

30MVAr's from an OFTO (Hybrid)	£2,450,535.
30MVAr's from an OFTO (Full Statcom)	£4,105,750.
15MVAr's from an onshore Power Park Module	£1,225,268.
30MVAr's from a Transmission Owner	£3,765,000

Notes:

1. For an onshore wind farm it is assumed a PPM with 30MVAr capability would produce 15MVAr from the STATCOM and 15MVAr from the turbines. For an OFTO all 30MVAr would be produced by the STATCOM.

2. ETYS indicates National Grid STATCOM figures as £4.86M-£5.94M for 50MVAr and £14.7M-£17.8M for a 100MVAr. For 100MVAr SVC the figures quoted are £9.5M-£11.7M. These were used to produce an average cost / MVAr which was then used to calculate the 30MVAr for the TO. Similar calculations were used for the 30MVAr OFTO and 15MVAr PPM costs but using costs kindly provided by developer's.

3. 100MVAr Cap is £5.8M-£7.2M and a 100MVAr reactor is £3.7M-£4.5M both of which would be required to replace a 100MVAr STATCOM or SVC. From these figures, a TO replacement of 50-100% of the STATCOM/SVC's with capacitors and reactors, would only achieve a 7.5-15.5% saving.

High Speed Auto Reclose

6.6 High Speed Auto Reclose would remove many of the drivers for the new requirement. It would replace the DAR currently used on the transmission system, as it performs a similar function but reinstates the lines in sub 1 second timescales. The likelihood of the voltage control system being required to respond is therefore considerably reduced.

6.7 If implemented it would initially be considered on a connection by connection basis, affecting key circuits locally to the new connection, but significant costs could be incurred where SQSS limits cannot be guaranteed.

6.8 The extent to which costs are incurred on the affected circuits depends on the age and type of circuit breakers fitted at the ends of the lines. For example, the older generation of air blast circuit breakers would need replacing with a modern breaker capable of meeting the duty.

6.9 Irrespective of whether the existing breaker is satisfactory or replaced, additional costs are incurred in relation to the switchgear control system[1]. For each line the costs incurred are likely to be:

Breaker replacement (275-400kV) at one end of the line only £1.1M-£4.0M

Switch gear control scheme on a circuit basis is estimated to be £500k

6.10 For High Speed Auto Reclose to work, all breakers associated with a circuit will need to be assessed and converted for HSAR operation. Furthermore, specific Generator connections may affect multiple circuits.

6.11 The required reliability of the HSAR may require the controls and associated systems to be duplicated which partially accounts for the increased cost.

6.12 As the proportion of renewable generation increases, so does the level of risk and the probability that key routes not already converted to High Speed Auto Reclose would require upgrading. The exact proportion of the network that would require upgrading would depend on the scenario under consideration. However as voltage control would still be required these costs would be additional.

6.13 Implementing High Speed Auto Reclose would incur considerable additional costs and could have unintended consequences.

Generators Provide Full STATCOM or SVC

6.14 Under this option the Generators would simply provide full STATCOM's and Hybrid STATCOM's would effectively be prohibited. Developers and Manufacturers, currently operating in GB, have indicated this would typically incur a cost increase of 35 to 40% on the installed equipment cost.

[1] According to ETYS 275 & 400 kV AIS bays are £1.1M-£1.4M GIS are £2.8M-£3.0M and £3.3M-£4.0M for 275kV and 400kV respectively. Although no published figures exist for the control scheme the TO believe the upgrade cost would be of the order of £500k

Hybrid STATCOM / SVC's with Improved Performance

6.15 The proposed Grid Code change is technology neutral, with the intention of allowing manufacturers and developers the flexibility to select one of a range of solutions including Hybrid STATCOM / SVC's. Whilst, for reasons described elsewhere, it might not under all circumstances be the best option from a technical perspective, it's is believed to provide an appropriate level of security in the most economic manor.

6.16 The cost incurred to Hybrid STATCOM / SVC's as a result of the proposed Grid Code change is detailed in the manufacturer's survey in section 5.131. For most designs this cost is negligible when compared to the other options.

6.17 However, it has been identified by manufacturers of hybrid solutions that utilise switched capacitors at the substations that the proposed repeatability requirement would result in increased costs. This would be due to design and equipment modifications to the ancillary and/or control equipment that would increase the cost of the switched capacitor unit by up to 20%. This would be considered significant on small installations with requirements for this Grid Code performance.

6.18 In relation to paragraph 6.17 the following points should also be given consideration:

1. The proposed Grid Code proposals only affect Power Park Modules greater than 50MW in E&W, 30MW in Southern Scotland and 10MW in Northern Scotland.
2. Looking at typical published costs / MW of an installed onshore wind farm (e.g. £800k/MW) the total impact on the cost of the smallest wind farm in Northern Scotland (i.e. 10MW) is 0.33% on the total cost.
3. The only solution considered, is from one supplier. Once a market has been created, there is the possibility that competition will emerge.
4. Whilst the % cost increase on the wind farm is small, any incremental cost will have an impact on profitability of a project, especially if not identified at the design stage.

Clarity of Text

6.19 Generators and Developers have stated that any ambiguity in the requirements of the Grid Code represents a financial risk. Normally any problems only become evident during the Compliance Tests, by which time correction of noncompliance is often expensive. It is therefore necessary to ensure the Grid Code requirements are expressed as clearly as possible.

6.20 To date Compliance Tests have only revealed repeatability issues relating to mechanically switched reactive elements (i.e. capacitors and reactors). However manufacturers prefer that the repeatability requirement is expressed in relation to the output of the Power Park Module as this allows them the maximum flexibility in managing the number of switching operations.

6.21 The wording used aims to meet this objective, allowing manufacturers to use extended short term capability and other means whilst ensuring the repeatability requirements meet the needs of the Transmission System and any inadequacies related to the switches do not reoccur.

6.22 It was known that some manufacturers would be concerned about the potential wear on the switches which typically have a life in the range of 10000 and 100000 operations. It was proposed that this was addressed either through:

6.22.1 An alarm and then a request to the NGET Control Room to reduce the reactive range by locking switches in or out

6.22.2 Automatically locking the switches after a specified number of operations

6.23 Manufacturers were consulted and they stated they didn't have control of their equipment once it was installed at site and consequently they would prefer to be able to lock the switches out automatically after 25 events.

6.24 NGET Control Room Staff were also consulted and they agreed to this request but indicated that under these circumstances they would need to be notified that the equipment had a limited reactive capability.

Communications and other issues beyond switching

6.25 Developers and Manufacturers have raised concerns that repeatability issues may arise during the system integration phase of the projects, where equipment from different manufacturers is connected together to provide the necessary overall response.

6.26 To date Compliance Tests have only established repeatability issues relating to mechanically switched components. During discussions it was concluded that whilst it is unlikely that system integration issues would only affect the repeatability, they cannot be entirely discounted.

Logged Data from Wind Farms

6.27 One developer stated that:

- The severity of voltage disturbance at the location of the installed equipment depends on the distance and network to the fault location or power system contingency. Therefore considerable care should be taken when making the assumption that described events i.e. due to lightning strikes, will lead to voltage events of sufficient magnitude as to require a switching response from hybrid STATCOM systems; and
- Measured results at transmission and distribution connected PPM indicate that over a period of two years there were no transient voltage events of sufficient magnitude to exhaust the PPM voltage control capability and thus require a switching response from the installed hybrid STATCOM system.

Cost Implications

6.28 Any design change incurs an associated cost for the engineering time and any testing, hardware modification etc. Furthermore there maybe additional cost implications which extend beyond the design phase if there are changes to the manufacturing process or materials used.

6.29 The workgroup has attempted to assess the impact of these changes which are detailed in the manufacturer's survey results in Table 5.131.1 and section 6 (Cost Benefit Analysis).

Compliance Testing

6.30 Compliance with the Grid Code is principally the responsibility of the User. To record compliance, National Grid asks for statements of compliance with the individual clauses of the Grid Code and these statements will be extended to reflect the new repeatability clauses. As part of this working group National Grid has stated that there is no general expectation of asking users as part of compliance testing to demonstrate long sequences of multiple reactive responses. However, a test of a single repeat response may be requested on new plant or in the event of evidence of noncompliance.

Fault Ride Through

6.31 The workgroup has attempted to assess the impact of FRT changes which are detailed in the manufacturer's survey results in Table 5.131.1.

7 Specific Issues for Transmission Licensees

Operational Issues – Limited Reactive Reserve

7.1 Traditional Synchronous Generation produces a voltage source which under short circuit conditions, acts as though it's located behind an impedance. As a consequence synchronous machines typically produce reactive current and power which is considerably higher than their rating when a fault occurs. This current will increase with the severity of the voltage depression and this helps with voltage recovery.

7.2 STATCOM's and convertor equipment typically limit the current contribution to a level governed by the Semiconductor rating. In many cases this rating may be higher than the maximum continuous rating by a factor of 2 or 3. This higher rating is typically available for short periods and usually this period exceeds the fault duration. A STATCOM may therefore inject a higher current during a short circuit.

7.3 However this additional current is supplied at the manufacturer's discretion. Furthermore for close up short circuits where the voltage drops to very low level's, the equipment may not be capable of injecting any additional current as the device may enter blocking mode.

7.4 Typically SVC's and discrete reactor and capacitors have a linear voltage / current characteristic. For voltages outside the normal operating range, the current will drop proportionally with the voltage. As with the STATCOM, the SVC may also block at a specific low voltage further reducing the reactive current injection, resulting in reducing performance.

Changing Characteristic of the Transmission System

7.5 These characteristics make these devices less beneficial for voltage support. At the current time there is no evidence to suggest that this is a problem for the GB Transmission System and this should therefore have no bearing on the outcome of his working group.

7.6 However with increased deployment of new generation technologies, the nature and characteristics of the Transmission System are changing and it is quite feasible that issues relating to voltage control may need further consideration in the future.

Guaranteeing Response

7.7 The SO and TO's regularly run studies to ensure the Transmission System is compliant with the SQSS (both pre and post fault). One of the main objectives of this work is to guarantee control room staff that appropriate MVAr response is delivered during critical system events.

7.8 In addition it is necessary to limit the number of studies required to secure the system to a manageable scale.

8 Implementation Considerations

Retrospective application

8.1 Retrofitting equipment imposes significant costs and delays, and in some cases may be practically impossible due to space constraints. Therefore no retrofitting will be required for existing plant unless subject to the modification application process and the new requirements will only apply to plant with a completion date on or after December 2017.

When should new requirements apply from?

8.2 It is proposed that this Grid Code change is implemented from December 2017. This is believed to give sufficient time for Generators and manufacturers to implement a solution and National Grid to assess and amend the online security assessment model.

Which generation should this apply to?

8.3 The modification proposed applies to all Power Park Modules and OTSDUW parties.

European Network Codes

8.4 With regard to RfG, unless identified as part of the implementation phase, the workgroup is taking the position that the Grid Code changes recommended in this document are consistent with RfG as RfG makes no specific recommendation on repeatability (see section 0).

Development of Legal Text

<u>Connection Conditions CC.A.7.2.3.1</u>

8.5 The proposed change to CC.A.7.2.3.1 (ii) clarifies an understanding between National Grid and Developers and Manufacturers that CC.A.7.2.3.1 (ii) that the 90% of the response required to be delivered in 1 second, relates to 50% of the full reactive power range e.g. unity to 90% of Qmax (or Qmin) or visa versa, where Qmax and Qmin are the maximum and minimum reactive power requirements, as detailed in CC.6.3.2.

8.6 In addition the changes allow a further second for a transition from fully leading to fully lagging and relaxes the settling time requirement from 1 to 2 seconds.

8.7 CC.A.7.2.3.1(ii) states "…for a sufficiently large step…" without stating the quantity which in the past has caused some confusion. This is because the step change required is dependent on the droop setting. Unity to fully lagging requires a 2% step for a 2% droop or a 7% step for a 7% droop. Likewise a 4% or 14% step is required from fully leading to fully lagging and visa-versa for 2% and 7% droop's respectively

<u>Connection Conditions CC.A.7.2.3.2</u>

8.8 The intention of the proposed change is to ensure that equipment installed from the 1st of December 2017 onwards is capable of switching the capacitors and reactors repetitively at 15 second intervals, to avoid reducing the level of system security. The wording describes the functionality and doesn't refer directly to the capacitors and reactors as it aims to remain technology neutral and allows manufacturers to use any means at their disposal to provide equivalent or better performance.

8.9 15 seconds was chosen as this guarantees operation consistent with DAR timescales and because some switch types have a spring recharge time which is typically 15 seconds. 15 seconds therefore also provides manufacturers with a wide range of switch types.

8.10 Limiting the number of events to 5 events in any 5 minute period allows the manufacturers cooling time between events sequences whilst guaranteeing the equivalent of an open close event every minute.

8.11 CC.A.7.2.3.2(ii) allows manufacturers to automatically stop and limit the number of switch events after 25 switch close operations but requires them to initiate an alarm and inform NGET that they now have limited reactive capability. For systems with more than one switch the limit should only be applied to a specific switch after 25 switch close operations occur on the switch concerned. Furthermore, it requires that any automated limits applied to switching events are removed within 6 hours unless otherwise agreed with NGET.

8.12 Equipment must be capable of responding to the three examples in Table 8 as described by the proposed CC.A.7.2.3.2. These detail the fastest sequences expected and one quick random sequence.

Event	**Example 1 (secs) (Shortest Time)**	**Example 2 (secs) (Evenly Spaced)**	**Example 3 (secs) (Random)**
1	0	0	0
2	15	60	16
3	30	120	40
4	45	180	63
5	60	240	111
6	300	300	243
7	315	360	301
8	330	420	355
9	345	480	376
10	360	540	466
11	600	600	626
12	615	660	644
13	630	720	698
14	645	780	895
15	660	840	945
16	900	900	1019
17	915	960	1118
18	930	1020	1219
19	945	1080	1294
20	960	1140	1320
21	1200	1200	1356
22	1215	1260	1372
23	1230	1320	1470
24	1245	1380	1585
25	1260	1440	1621

Table 8: Event Sequences

Addition to Fault Ride Provisions in CC.6.3.15

8.13 The intention of the propose change to CC.6.3.15, is to ensure switched reactive compensation plant does not switch in or out during the initial phase of the fault (typically 80 to 140ms).

8.14 Once the fault is cleared, the initial voltage depression has passed and the voltage recovery phase is underway, equipment may then change the switch states to initiate the normal reactive response as defined by CC.A.7.2.2.5 and CC.A.7.2.3.1. This is not expressed as obligatory requirement as manufacturers may choose to provide the response using a variety of sources and may not need to initially change the switch state.

Changes to Balancing Codes

8.15 The change to the Balancing Code identifies the operational requirement to immediately inform NGET if the equipment automatically limits the reactive power. It also states that reduction in reactive capability which is initiated as a result of 25 events described in CC.A.7.2.3.2(ii) will automatically be restored in six hours.

8.16 Some of the wording is repeated in both sections i.e. BC2.11.4 and CC.A.7.2.3.2(ii) in order to emphasize and establish the link between these sections and to ensure any future changes to the code are applied to all relevant sections. The Balancing Code describes the operational requirement and the Connection Conditions the design requirement.

8.17 CC.A.7.2.3.2(ii) is explicitly mentioned in connection with the 6 hour restoration, to ensure users are not confused and assume that plant break downs resulting in limited reactive capability, must be fixed within 6 hours. This is not the case, as the 6 hours only applies to the 25 events defined in CC.A.7.2.3.2(ii).

9 Conclusions and Recommendations

9.1 The proposed draft legal text covered in Annex 3 of this report was developed over several iterations which were discussed amongst the workgroup. The initial proposal related solely to repeatability criteria whilst also requiring discrete compensation devices to remain connected during faults or voltage disturbances.

9.2 These proposals were further updated to define a repeatability criteria based on a limit of 5 events in 2 minutes with no more than 25 events in any 24 hour period. In addition further clauses were added requiring Generators to notify NGET of a declared reduction in reactive capability following 25 events.

9.3 The final proposal (as per Annex 3 of this Consultation) was then developed which aims to address the Grid Code defects by clarifying the following:-

- The time frame required for a Power Park Module or Reactive Compensation equipment to transit from full lead to full lag or visa versa.
- Clarifications to the settling time following a disturbance
- The addition of a repeatability criteria requiring 5 consecutive responses in any five minute period, no more than 15 seconds apart.
- A criteria which limits the maximum number of events (ie unity to 90% full leading or unity to 90% full lagging) to a maximum of 25 events in any 24 hour period.
- Where the daily limit of 25 events is exceeded the requirement to inform NGET of the reduction in reactive capability which should be available as soon as possible but in any event no longer than 6 hours after the reduction
- Amendments to the fault ride through requirements clarifying reactive compensation equipment and requirements preventing them from switching during a fault ride through sequence.

9.4 The performance requirements specified above are believed to be satisfactory for the immediate future and covers the majority of the most severe storm events but is not guaranteed to cover or provide support for all modes of dynamic instability and interaction between controllers. As the response may be too slow or time limited.

9.5 As the dynamic performance of the system is changing rapidly and radically, the voltage control methodology along with other aspects of the dynamic performance will need to be kept under review.

9.6 It's possible that this subject will need reviewing in the future should further system need arise from changes in system characteristics.

9.7 The workgroup believes the recommended option is consistent with RfG and meets the minimum needs of the Transmission System.

9.8 In a rapidly changing electricity system which is increasingly dependent on non-synchronous generators for dynamic response: the proposed legal text guarantees equipment performance in planning and operational time scales, giving the operators confidence that equipment is able to respond within DAR timescales. It also clearly sets out procedures for limited availability.

9.9 Some parties felt the existing Grid Code was ambiguous. The proposed change aims to ensure there is no ambiguity and the minimum requirement is clearly established allowing manufacturers and developers to compete on an equitable basis. Whilst most manufacturers and developers have sited some increases, others have indicated either no increase or marginal changes in cost. It also ensures NGET is not dependant on some generators exceeding the requirements to make up any shortfall elsewhere on the system.

Recommendations

9.10 It is recommended that the content of this report and the corresponding proposed legal text is progressed for industry consultation.

10 Assessment

Impact on the Grid Code

10.1 The modifications proposed to the Connection Conditions and the Balancing Code are detailed in Annex 3 - Proposed Legal Text of this report.

Impact on Grid Code Users

10.2 This modification impacts the Developers, Manufacturers and Owners of Power Park Modules and Offshore Transmission Networks.

Impact on National Electricity Transmission System (NETS)

10.3 State estimators, system models, and modelling algorithms may need to be changed to reflect the new reactive power control methodology.

Impact on Greenhouse Gas emissions

10.4 None

Assessment against Grid Code Objectives

10.5 The Grid Code Objectives:

(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

The Proposal minimises operational risks and the planning required for severe events and has minimal impact on generators and manufacturers and provides clarity of the requirement.

(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

The proposal has minimal impact on generators and manufacturers. Hybrid devices will be able to be used with minimal impact on cost. Current timing requirements offer manufacturer's the widest options of switch choices available whilst ensuring the majority of system events are covered.

(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole; and

The proposal minimises studies and operational complications and planning for severe events. Has minimal impact on generators and manufacturers. Ensures the majority of events are covered.

(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.

The proposals have no interaction with the relevant European Codes, which in this case is the Requirement for Generators.

Impact on core industry documents

10.6 This document contains proposals to change the GB Grid Code. Further consideration should be given with regard to the STC, which may require changes.

Impact on other industry documents

10.7 None

Impact on Bilateral Agreements

10.8 None

Implementation

10.9 The Workgroup proposes that, should the proposals be taken forward, the proposed changes be implemented 10 business days after an Authority decision.

11 Responding to this Consultation

11.1 Views are invited upon the proposals outlined in this consultation, which should be received by 6 January 2016 using the proforma provided.

11.2 Responses may be emailed to grid.code@nationalgrid.com.

11.3 The proposals set out in this consultation are intended to better meet the Grid Code Objectives. To achieve this, they are intended to facilitate efficient and economic connection arrangements whilst ensuring there is no impact on the safety and security of the transmission system, and no discernible impact on the visual disturbance to electricity consumers.

11.4 Responses are invited to the following questions:

(i) Do you support the proposed approach? Please clarify why.

(ii) Do you believe that GC0075 better facilitates the appropriate Grid Code objectives? If not, why do they fail to do so?

(iii) Do the proposed changes facilitate efficient connection and operation of new and/or existing Power Park Modules which utilise Hybrid Statcoms / SVC's? If not, why do they fail to do so?

(iv) Do the proposed changes impose any additional material risks on the System Operator, e.g. reduced stability margins, reduced reactive capability margins, or difficulty in managing transmission system voltages? If yes, please highlight these risks.

(v) Do the proposed changes impose any additional material risks on Transmission Owners, e.g. additional investment that might be neither economic nor efficient? If yes, please highlight these risks.

(vi) Do the proposed changes adequately protect the interests of all Transmission System Users? If not, why do they fail to do so?

(vii) Are there further technical considerations to be taken into account? If yes, please highlight these technical considerations.

(viii) Is there any evidence that Users will be inappropriately or adversely affected by the changes proposed? If so, please provide details.

(ix) Do the modifications proposed strike an appropriate balance between the needs of Generators, Transmission Licensees, and other interested parties? If not, why do they fail to do so?

(x) Please provide any other comments you feel are relevant to the proposed change.

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

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

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

Grid Code Review Panel

GC0075 Hybrid Static Compensators - Update

Date Raised: 20 Nov 2013

GCRP Ref: pp13/67[1]

A Panel Paper by Graham Stein / Richard Ierna

National Grid

Summary
Power Park Module developers have been installing Hybrid STATCOM / SVC's, which provide a portion (typically 50% to 75%) of their reactive capability from switched reactors and capacitors. Some of these devices have restrictions preventing repeated switching in a short period which can be seen as inconsistent with the concept of "continuously acting" control which is required by the Grid Code. Interested parties believe clarification is required of the Grid Code requirements on these devices and that it would be beneficial to form a Workgroup to develop proposals for clearer and more appropriate requirements on Hybrid STATCOM / SVC performance.

Users Impacted
High *– None Identified*
Medium *– Owners and developers of Power Park Modules – reduced risk of non-compliance and more appropriate performance requirements.*
Low *– None Identified*

Description & Background
During compliance testing of new Power Park Modules it emerged that some manufacturers had interpreted the various references in the Grid Code to continuous voltage control, as a single linear increase or decrease in reactive power. National Grid's interpretation of the Code was that voltage control should be continuously available and that the equipment in question had unacceptable delays before the performance could be repeated. Manufacturers have indicated that the current performance regarding delays in operation, are driven by the switch gear, capacitor discharge and associated controls.
In addition, some manufacturers switch out the capacitors during a fault which could also be interpreted as a non-compliance. With regard to switching out capacitors several manufacturers have indicated that this is due to customer requests to do so, or to prevent over-voltage issues occurring.
Manufactures have identified a benefit in reduced costs of Hybrid designs compared to supplying a fully rated STATCOM / SVC. National Grid is keen to ensure that any potential shortfall in voltage control does not adversely impact on system security, or necessitate additional investment in alternatives, by achieving adequate discrimination between voltage control actions and network actions such as Delayed Auto Reclose.

1 The Code Administrator will provide the paper reference following submission to National Grid.

National Grid convened a workshop on the 20th September 2013 to seek an up to date view from interested parties which was attended by representatives of equipment suppliers and generation developers. Developers provided feedback to indicate that inconsistency in interpretation of the current requirements continued to present a material risk to their projects. Manufacturers highlighted that different interpretations by different manufacturers meant that some parties could be

disadvantaged.

Proposed Solution

As an alternative to developers purchasing a fully rated STATCOM or thyristor switched shunt elements, National Grid has asked whether manufactures can improve the switchgear, capacitor discharge and control performance, possibly removing the need for fast discharge of the capacitors, and ensure it is not necessary to disconnect the capacitors at higher short circuit voltages.

Developers and manufacturers have asked that National Grid review the benefits that faster and repeatable actions from static components provide to the system, and to clarify the requirement to generate maximum reactive current during a fault.

Workshop attendees expressed a strong desire for these questions to be addressed and proposals for changes to the Grid Code to be progressed by an appropriate workgroup.

Assessment against Grid Code Objectives

The improvement in performance proposed, aims to allow manufacturers, developers and generators to benefit from the cost reduction offered by Hybrid STATCOM / SVC's whilst restoring some of the capability lost, thereby improving system security and operability.

Clarification of the Grid Code will minimise the financial risk, posed by non-compliance to developers and manufacturers. It will also minimise the risk of Transmission Licensees having to make up a shortfall in reactive capability with alternative sources.

We believe the proposed changes to the Grid Code better facilitate the Grid Code Objectives:

(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

The main cost saving offered by Hybrid STATCOM / SVC's would be available provided their performance meets the minimum needs of the System.

(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

Transparency of requirement and clarification of the code creates a market in which all manufacturers, developers and generators are able to compete fairly without the burden of unnecessary risk.

(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole;

Clarity of the requirement and subsequent improvement in performance, such that most of the originally intended capability is restored, whilst allowing the use of Hybrid solutions provides, in our view, the best compromise between ensuring system security and efficiency of delivery.

(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.

Future system security will be maintained assuming adequate improvement in performance can be achieved in a timely manner.

Impact & Assessment

Impact on the National Electricity Transmission System (NETS)
Hybrid STATCOM/SVC performance as proposed would ensure security of supply is maintained and will provide greater resilience with respect to voltage collapse.
Impact on Greenhouse Gas Emissions
None
Impact on core industry documents
The Grid Code will be modified to clarify the requirements on Hybrid STATCOM / SVC's.
Impact on other industry documents
There may be a need to review similar provisions in STC Section K.

Supporting Documentation
GC0075 Hybrid Statcom Draft WG ToRs.doc Hybrid_STATCOM_SVC_Workshop_20_09_2013.pdf

Recommendation
The Grid Code Review Panel is invited to: Progress this issue to a Workgroup with the aim of clarifying the Grid Code so that the performance requirements of Hybrid STATCOM / SVC's are defined appropriately.

Document Guidance

This proforma is used to raise an issue at the Grid Code Review Panel, as well as providing an initial assessment. An issue can be anything that a party would like to raise and does not have to result in a modification to the Grid Code or creation of a Working Group.

Guidance has been provided in square brackets within the document but please contact National Grid, The Code Administrator, with any questions or queries about the proforma at grid.code@nationalgrid.com.

GC0075 HYBRID STATIC COMPENSATOR

TERMS OF REFERENCE

Governance

1. The Hybrid Static Compensator Workgroup was established by Grid Code Review Panel (GCRP) at the [November 2013] GCRP meeting.

2. The Workgroup shall formally report to the GCRP.

Membership

3. The Workgroup shall comprise a suitable and appropriate cross-section of experience and expertise from across the industry, which shall include:

Name	Role	Representing
Graham Stein	Chair	
Franklin Roderick	Technical Secretary	
Antony Johnson / Richard Ierna	National Grid Representative	National Grid
	Industry Representative	[PPM Developers]
	Industry Representative	[Hybrid STATCOM Equipment Manufacturers]
	Industry Representative	[Transmission Owners]
	Authority Representative	Ofgem
	Observer	

Meeting Administration

4. The frequency of Workgroup meetings shall be defined as necessary by the Workgroup chair to meet the scope and objectives of the work being undertaken at that time.

5. National Grid will provide technical secretary resource to the Workgroup and handle administrative arrangements such as venue, agenda and minutes.

6. The Workgroup will have a dedicated section on the National Grid website to enable information such as minutes, papers and presentations to be available to a wider audience.

Scope

7. The Workgroup shall consider and report on the following:

- The performance of Hybrid Static Compensators and comparable equipment with respect to repeatability and the supply of reactive current during a fault

- The performance required from voltage control equipment within Power Park Modules to control voltage on the networks in the steady state, during and after secured events, and in the event of a wider system disturbance.

Deliverables

8. The Workgroup will provide updates and a Workgroup Report to the Grid Code Review Panel which will:

- Detail the findings of the Workgroup;
- Draft, prioritise and recommend changes to the Grid Code and associated documents in order to implement the findings of the Workgroup; and
- Highlight any consequential changes which are or may be required,

Timescales

9. It is anticipated that this Workgroup will provide an update to each GCRP meeting and present a Workgroup Report to the [Timetable to be discussed] GCRP meeting.

10. If for any reason the Workgroup is in existence for more than one year, there is a responsibility for the Workgroup to produce a yearly update report, including but not limited to; current progress, reasons for any delays, next steps and likely conclusion dates.

New text is shown in Red

Connection Conditions

CC.A.7.2.3 Transient Voltage Control

CC.A.7.2.3.1 …

…

(ii) the response shall be such that, for a sufficiently large step, 90% of the full leading or lagging reactive capability of the **Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, as required by CC.6.3.2 (or, if appropriate, C.A.7.2.2.6 or CC.A.7.2.2.7), from unity power factor will be produced within 1 second. For **Plant and Apparatus** installed on or after 1 December 2017, 90% of a change in reactive output from full leading to full lagging or full lagging to full leading shall be achieved within 2 seconds.

…

(iv) the settling time shall ~~be~~ take no ~~than~~ longer than 2 seconds from ~~the application of the step change in voltage and~~ 90% of the response being achieved as defined in CC.A.7.2.3.1 (ii) after which the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state Reactive Power ~~within this time~~.

…

CC.A.7.2.3.2 In addition to the requirements of CC.A.7.2.3.1, reactive compensation plant and equipment installed on or after 1 December 2017 should be capable of:

(i) providing 5 or more responses in accordance with CC.A.7.2.2.5 and CC.A.7.2.3.1 in any 5 minute period, where each response crosses the reactive range (0.95PF leading to 0.95PF lagging or visa-versa) and returns again. The 5 consecutive responses may occur at intervals of 15 seconds or more.

(ii) providing 25 or more responses from unity to 90% full leading and unity to 90% full lagging and vice versa ~~as described in CC.A.7.2.3.2(i)~~ in any 24 hour period. After which the **Generator** may if necessary, restrict the reactive capability in one or both the leading and lagging region, as applicable. The **User** must declare to **NGET** any restriction to reactive capability as defined in BC2.11.4. The full reactive capability as defined under CC.6.3.2(c) shall be fully available as soon as practicable and within 6 hours of the final event unless otherwise agreed with **NGET**.

CC.6.3.15 Fault Ride Through

…

CC.6.3.15.1 Fault Ride through applicable to Generating Units, Power Park Modules and DC Converters and **OTSDUW Plant and Apparatus**

(a) Short circuit faults on the **Onshore Transmission System** (which may include an **Interface Point**) at **Supergrid Voltage** up to 140ms in duration.

(i) Each **Generating Unit**, **DC Converter**, or **Power Park Module** and any constituent **Power Park Unit** thereof and **OTSDUW Plant and Apparatus** shall remain transiently stable and connected to the **System** without tripping of any **Generating Unit**, **DC Converter** or **Power Park Module** and / or any constituent **Power Park Unit** or reactive compensation equipment and **OTSDUW Plant and Apparatus**, for a close-up solid three-phase short circuit fault or any unbalanced short circuit fault on the **Onshore Transmission System** (including in respect of **OTSDUW Plant and Apparatus**, the **Interface Point**) operating at **Supergrid Voltages** for a total fault clearance time of up to 140 ms. A solid three-phase or unbalanced earthed fault results in zero voltage on the faulted phase(s) at the point of fault. The duration of zero voltage is dependent on local **Protection** and circuit breaker operating times. This duration and the fault clearance times will be specified in the **Bilateral Agreement**. Following fault clearance, recovery of the **Supergrid Voltage** on the **Onshore Transmission System** to 90% may take longer than 140ms as illustrated in Appendix 4A Figures CC.A.4A.1 (a) and (b). It should be noted that in the case of an **Offshore Generating Unit**, **Offshore DC Converter** or **Offshore Power Park Module** (including any **Offshore Power Park Unit** thereof) which is connected to an **Offshore Transmission System** which includes a **Transmission DC Converter** as part of that **Offshore Transmission System**, the **Offshore Grid Entry Point** voltage may not indicate the presence of a fault on the **Onshore Transmission System**. The fault will affect the level of **Active Power** that can be transferred to the **Onshore Transmission System** and therefore subject the **Offshore Generating Unit**, **Offshore DC Converter** or **Offshore Power Park Module** (including any **Offshore Power Park Unit** thereof) to a load rejection.

(ii) Each **Generating Unit**, **Power Park Module** and **OTSDUW Plant and Apparatus**, shall be designed such that upon both clearance of the fault on the **Onshore Transmission System** as detailed in CC.6.3.15.1 (a) (i) and within 0.5 seconds of the restoration of the voltage at the **Onshore Grid Entry Point** (for **Onshore Generating Units** or **Onshore Power Park Modules**) or **Interface Point** (for **Offshore Generating Units**, **Offshore Power Park Modules** or **OTSDUW Plant and Apparatus**) to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), **Active Power** output or in the case of **OTSDUW Plant and Apparatus**, **Active Power** transfer capability, shall be restored to at least 90% of the level available immediately before the fault. Once the **Active Power** output, or in the case of **OTSDUW Plant and Apparatus**, **Active Power** transfer capability, has been restored to the required level, **Active Power** oscillations shall be acceptable provided that:

- the total **Active Energy** delivered during the period of the oscillations is at least that which would have been delivered if the **Active Power** was constant

- the oscillations are adequately damped

During the period of the fault as detailed in CC.6.3.15.1 (a) (i) for which the voltage at the **Grid Entry Point** (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) is outside the limits specified in CC.6.1.4, each **Generating Unit** or **Power Park Module** or **OTSDUW Plant and Apparatus** shall generate maximum reactive current without exceeding the transient rating limit of the **Generating Unit**, **OTSDUW Plant and Apparatus** or **Power Park Module** and / or any constituent **Power Park Unit** or reactive compensation equipment. Switched reactive compensation equipment's (such as mechanically switched capacitors and reactors) will not connect or disconnect during the fault but may act to assist in post fault voltage recovery.

…

CC.6.3.15.2 Fault Ride Through applicable to Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station who choose to meet the fault ride through requirements at the LV side of the Offshore Platform

(a) Requirements on **Offshore Generating Units**, **Offshore Power Park Modules** and **Offshore DC Converters** to withstand voltage dips on the **LV Side of the Offshore Platform** for up to 140ms in duration as a result of faults and / or voltage dips on the **Onshore Transmission System** operating at **Supergrid Voltage**

(i) Each **Offshore Generating Unit**, **Offshore DC Converter**, or **Offshore Power Park Module** and any constituent **Power Park Unit** thereof shall remain transiently stable and connected to the **System** without tripping of any **Offshore Generating Unit**, or **Offshore DC Converter** or **Offshore Power Park Module** and / or any constituent **Power Park Unit** or reactive compensation equipment, for any balanced or unbalanced voltage dips on the **LV Side of the Offshore Platform** whose profile is anywhere on or above the heavy black line shown in Figure 6. For the avoidance of doubt, the profile beyond 140ms in Figure 6 shows the minimum recovery in voltage that will be seen by the generator following clearance of the fault at 140ms. Appendix 4B and Figures CC.A.4B.2 (a) and (b) provide further illustration of the voltage recovery profile that may be seen. It should be noted that in the case of an **Offshore Generating Unit**, **Offshore DC Converter** or **Offshore Power Park Module** (including any **Offshore Power Park Unit** thereof) which is connected to an **Offshore Transmission System** which includes a **Transmission DC Converter** as part of that **Offshore Transmission System**, the **Offshore Grid Entry Point** voltage may not indicate the presence of a fault on the **Onshore Transmission System**. The voltage dip will affect the level of **Active Power** that can be transferred to the **Onshore Transmission System** and therefore subject the **Offshore Generating Unit**, **Offshore DC Converter** or **Offshore Power Park Module** (including any **Offshore Power Park Unit** thereof) to a load rejection.

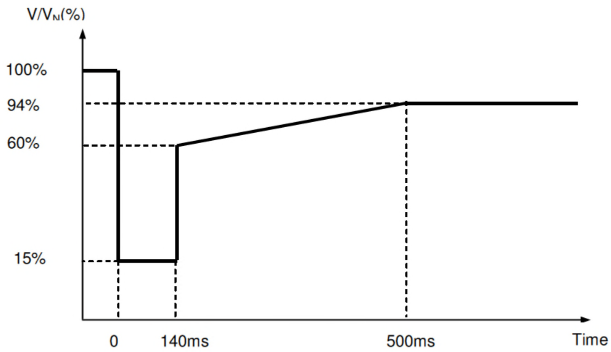


Figure 6

V/VN is the ratio of the actual voltage on one or more phases at the **LV Side of the Offshore Platform** to the nominal voltage of the **LV Side of the Offshore Platform**.

(ii) Each **Offshore Generating Unit**, or **Offshore Power Park Module** and any constituent **Power Park Unit** thereof shall provide **Active Power** output, during voltage dips on the **LV Side of the Offshore Platform** as described in Figure 6, at least in proportion to the retained voltage at the **LV Side of the Offshore Platform** except in the case of an **Offshore Non-Synchronous Generating Unit** or **Offshore Power Park Module** where there has been a reduction in the **Intermittent Power Source** in the time range in Figure 6 that restricts the **Active Power** output below this level and shall generate maximum reactive current without exceeding the transient rating limits of the **Offshore Generating Unit** or **Offshore Power Park Module** and any constituent **Power Park Unit** or reactive compensation equipment. Once the **Active Power** output has been restored to the required level, **Active Power** oscillations shall be acceptable provided that:

- the total **Active Energy** delivered during the period of the oscillations is at least that which would have been delivered if the **Active Power** was constant
- the oscillations are adequately damped and;

(iii) Each **Offshore DC Converter** shall be designed to meet the **Active Power** recovery characteristics as specified in the **Bilateral Agreement** upon restoration of the voltage at the **LV Side of the Offshore Platform**.

(b) Requirements of **Offshore Generating Units**, **Offshore Power Park Modules** to withstand voltage dips on the **LV Side of the Offshore Platform** greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.2. (a) each **Offshore Generating Unit** or **Offshore Power Park Module** and / or any constituent **Power Park Unit**, shall:

(i) remain transiently stable and connected to the **System** without tripping of any **Offshore Generating Unit** or **Offshore Power Park Module** and / or any constituent **Power Park Unit**, for any balanced voltage dips on the **LV side of the Offshore Platform** and associated durations anywhere on or above the heavy black line shown in Figure 7. Appendix 4B and Figures CC.A.4B.3. (a), (b) and (c) provide an explanation and illustrations of Figure 7. It should be noted that in the case of an **Offshore Generating Unit**, or **Offshore Power Park**

Module (including any **Offshore Power Park Unit** thereof) which is connected to an **Offshore Transmission System** which includes a **Transmission DC Converter** as part of that **Offshore Transmission System**, the **Offshore Grid Entry Point** voltage may not indicate the presence of a voltage dip on the **Onshore Transmission System**. The voltage dip will affect the level of **Active Power** that can be transferred to the **Onshore Transmission System** and therefore subject the **Offshore Generating Unit**, or **Offshore Power Park Module** (including any **Offshore Power Park Unit** thereof) to a load rejection.

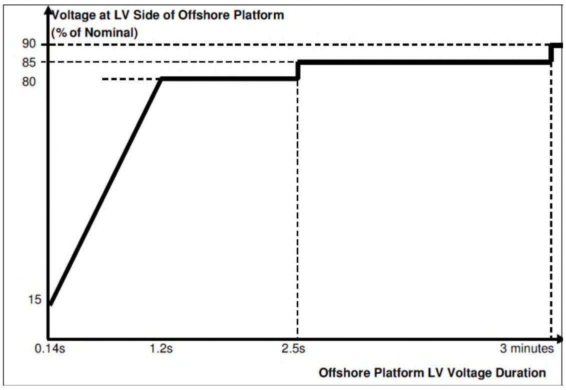


Figure 7

(ii) provide **Active Power** output, during voltage dips on the **LV Side of the Offshore Platform** as described in Figure 7, at least in proportion to the retained balanced or unbalanced voltage at the **LV Side of the Offshore Platform** except in the case of an **Offshore Non-Synchronous Generating Unit** or **Offshore Power Park** Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 7 that restricts the Active Power output below this level and shall generate maximum reactive current (where the voltage at the Offshore Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Offshore Generating Unit or Offshore Power Park Module and any constituent Power Park Unit or reactive compensation equipment. Switched reactive compensation equipment's (such as mechanically switched capacitors and reactors) will not connect or disconnect during the fault but may act to assist in post fault voltage recovery; and,

…

Balancing Code

BC2.11.4 Each Generator and / or DC Converter shall operate its dynamically controlled OTSDUW Plant and Apparatus, Power Park Module and / or DC Converter (as applicable) to ensure that the reactive capability and voltage control performance requirements as specified in CC.6.3.2, CC.6.3.8, CC.A.7 and the Bilateral Agreement can be satisfied in response to the Setpoint Voltage and Slope as instructed by NGET at the Transmission Interface Point or Grid Entry Point or User System Entry Point (where Embedded). Where a Power Park Module, DC Converter or OTSDUW Plant and Apparatus has been subject to more than the defined number of events as defined in CC.A.7.2.3.2(ii), each Generator or DC Converter OTSDUW Plant and Apparatus must notify NGET of any reduction in reactive capability and subsequently when full reactive capability is restored, which shall be not greater than 6 hours for events described in CC.A.7.2.3.2(ii).

11.7 The table below details the Workshop (WS) and Workgroup (WG) attendance. Workgroup members were additionally invited to answer the following question:

Do the proposals address the Grid Code defects? Yes/No

Name	Organisaton		WS	WG-1	WG-2	WG-3	WG-4	WG-5
Transmission Owners & Operators								
Richard Ierna	National Grid	Y, Y, Y						
Graham Stein	National Grid	Y, Y, Y						
Athony Johnson	National Grid	Y, Y, Y						
Razwan Pabat-Stro	Scottish Power	Y, Y, Y						
Developers								
Sridhar Sahukari	Dong Energy	NO						
Mustafa Kayikci	TNEI							
Lee Holdsworth	RES	Yes						
OFTOs								
Mike Lee	Transmission I							
Generators								
Mick Chowns	RWE	Yes						
Isaac Gutierez	Iberdrola/Scott	Yes						
Rui Rui	Iberdrola/Scott							
Damian Jackman	SSE Generation							
Manufacturers (Hybrids & Switch Gear)								
Peter Jones	ABB							
Anne Palesjo	ABB							
Alireza Mousavi	ABB							
Phillipe Maibach	ABB							
Simon Vogelsange	ABB							
Fahd Hashiesh	ABB							
Alireza Mousavi	ABB							
Matthias Gautschi	ABB							
Shafiu Ahmed	Siemens	Yes						
Chinglai Mor	Siemens							
Ian Cunningham	Alstom Grid							
Vesa Oinonen	Alstom Grid							
Martin Lyster	AMSC							
John Diaz de Leon	AMSC	Yes						
Steve Mortimer	S&C Electric							
Clifton Ellis	S&C Electric							
Mick Barlow	S&C Electric							
Laurent Poutrain	Vizimax							
Manufacturers (Wind Turbines)								
Peter Thomas	Nordex							
Amir Dahresobh	Nordex							
Charles Creswell	Senvion UK							
Niall Duncan	Senvion UK							
Sigrid Bolik	Senvion UK							
			9	16	13	16	17	9

Annex 5 – Acronyms and Abbreviations

This section contains abbreviations and acronyms used in this document.

Acronym / Abbreviation	Description
AC	Alternating Current
BC	Balancing Code
CB	Circuit Breaker
CC	Connection Conditions
CCS	Carbon Capture and Storage
cct	Circuit
CHP	Combined Heat and Power
CUSC	Connection and Use of System Code
DAR	Delayed Auto Reclose
DC	Direct Current
DFIG	Doubly Fed Induction Generator
EMF	Electro Motive Force
ENTSOe	European Network of Transmission System Operators for Electricity
ETYS	Electricity Ten Year Statement
HSAR	High Speed Auto Reclose
FES	Future Energy Scenario
FON	Final Operational Notification
FRT	Fault Ride Through
GB	Great Britain
GC	Grid Code
GCRP	Grid Code Review Panel
GW	Giga Watts
HCDC	High Voltage Direct Current
HV	High Voltage
KPI	Key Performance Indicators
kV	kilo Volts
LV	Low Voltage
M/C	Machine
MSC	Mechanically Switched Capacitor
Mths	Months
MVA	Mega Volt Ampere's – Apparent Power
MVAr	Mega Volt Ampere's Reactive – Reactive Power
MW	Mega Watts
NB	Nota Bene - Note Well
NETS	National Electricity Transmission System
NGET	National Grid Electricity Transmission
OEM	Original Equipment Manufacturer
OFGEM	Office of Gas and Electricity Markets
OFTO	Offshore Transmission Owner
OHL	Overhead Line
OTSDUW	Offshore Transmission System Developer User Works
P	Real Power (i.e. MW)
PF	Power Factor
Plc	Public Limited Company
POC	Point of Connection
POD	Power Oscillation Damping
PPM	Power Park Modules
pu	Per Unit
Q	Reactive Power (i.e. MVAr's)
RfG	Requirements for Generators
SF6	Sulphur Hexafluoride
SHETL	*Scottish Hydro Transmission Ltd.*
SQSS	*System Quality of Supply Standards*
STATCOM	*Static Compensator*
SO	System Operator

STC	System operator Transmission owner Code
SSD	Switched Shunt Device
SVC	Static VAr Compensator
TF	Transfer function
TO	Transmission Owner
UK	United Kingdom
V	Voltage
VN	Voltage Nominal (i.e. Nominal Volts)
vs	Verses
VT	Voltage Transformer
WF	Wind Farm
WG	Work Group