# GRID CODE REACTIVE POWER REVIEW SUB-GROUP

# REPORT TO THE GRID CODE REVIEW PANEL

## Contents

# 1. Summary

1.1 This report has been prepared by a sub-group of the Grid Code Review Panel to address the requirements arising from the TUG meeting on 25 February 2000, at which the Grid Code Review Panel (GCRP) was asked formally to initiate a review of the Grid Code requirements for the provision of reactive power. The requirement for such a review is set out in Schedule 5 of the Master Connection and Use of System Agreement ('MCUSA-5')[1] and is thus regarded as an adjunct to the development of a reactive power market.

# 2 Introduction

2.1 At a meeting of the Grid Code Review Panel on 15 June 2000, NGC tabled paper GCRP 00/13 and gave a presentation on the background to the review. Panel members were invited to provide comments on the issues raised by the paper and by the presentation. Following the meeting, three sets of written comments were subsequently received and at the next GCRP meeting on 7 September 2000 it was agreed that a sub-group should be established to carry out the review, with the Terms of Reference as shown in Appendix 1.

# 3 Issues Discussed

Issues fell into two main areas for discussion:-

a) Capability requirements at time of initial commissioning of new Generation, and

b) Ongoing operational requirements.

These issues are reviewed separately below.

## 3.1 Initial Capability

3.1.1 Agreement was quickly reached in the sub-group to the principle of the Grid Code requiring the reactive capability of all new generating units to be designed to IEC-34 Part 3 (the correct reference being EN 60034-3). It was accepted that this capability need not be maintained throughout the lifetime of the plant (subject to the maintenance of a minimum operational capability), provided that appropriate mechanisms are put in place to procure reactive capacity to meet the needs of the system. Discussions at the sub-group concentrated on ensuring that reference could be made to appropriate elements covered by this standard.

3.1.2 Alignment with EN60034-3 will mean the required minimum Short Circuit Ratio will change from 0.5 to 0.4 for most plant connecting directly to the NGC system. This

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[1] *MCUSA Schedule 5 para 2.5 (b) reads:* 'the Transmission Users Group shall be requested, no later than 31 March 2000, to invite the Grid Code Review Panel to review the provisions of the Grid Code with respect to Reactive Power in light of this Schedule.'

will increase a generating unit's load angle for a given power output and may reduce stability margins. However, the effect is complex (see Appendix 3f), and stability is influenced by several generating unit parameters that have never been specified in the Grid Code. If necessary, any specific technical requirements relating to an individual generation connection can be set out in the Supplemental Agreement.

3.1.3 In particular, discussions took place on the necessity for a reference to a "back-stop" value of rated power factor (see Appendix 3a). EN60034-3 specifies standard values for rated power factor but does not make them mandatory. The sub-group balanced the need to provide capability to maintain continuity in reactive security and facilitate a reactive market, against the imposition of unnecessary costs on the MW market. It was concluded that a maximum value of rated power factor was justified.

3.1.4 Whilst it is intended that the decision to repair reactive shortfalls will be left to generators in the light of reactive market incentives, significant changes to generating units that permanently alter their parameters would be notified to NGC and may be the subject of Modification Applications.

3.1.5 The proposal to replace the current Grid Code obligations of CC.6.3.2 with these new requirements will necessitate consequential changes to the description of various Ancillary Services described elsewhere in the Grid Code.

## 3.2 Operational Requirements

3.2.1 Discussions at the sub-group on operational requirements have recognised the principles of the majority of reactive requirements being procured via market mechanisms. There has been recognition of a minimal reactive range requirement to satisfy the needs of an individual generating unit, while coping with variations in system voltage and to cover the inevitable response immediately post a system event.

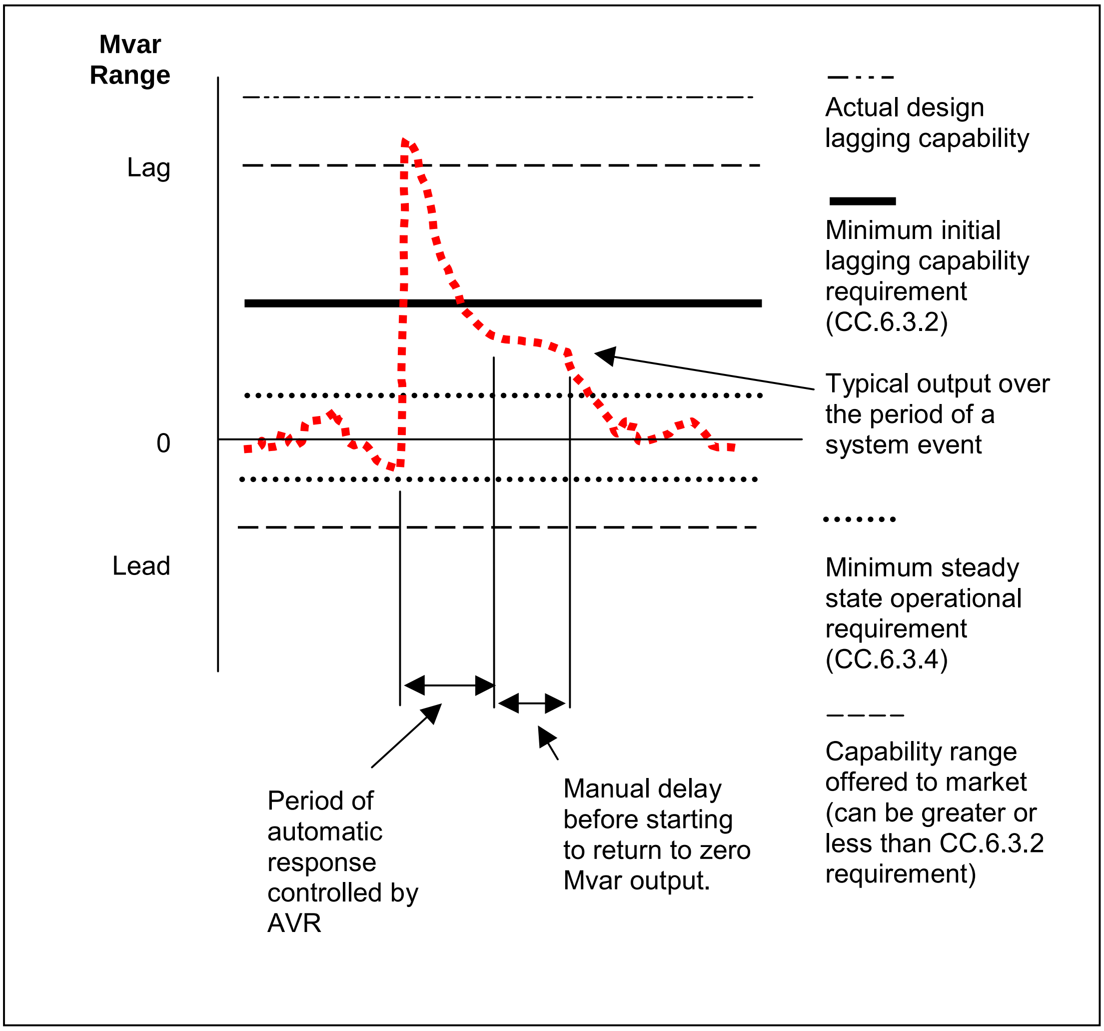
3.2.2 In order to develop the operational requirements, a scenario was considered in which each synchronised generator would fall into one of two categories:

a) participating in the reactive market and therefore being instructed to a particular Mvar output (or target voltage) in a similar manner to current arrangements; or

b) not participating in the reactive market and therefore expected to remain at or about a zero Mvar output (at HV).

The minimum operational requirements for any unit would thus be defined by the minimum performance characteristics that would allow a unit in category (b) to operate in a stable manner, securely, and without detriment to the system or other Users. These performance characteristics were explored by the sub-group.

3.2.3 In the case of a generating unit operating in the latter mode, stability considerations mean that the unit will need to operate with normal AVR characteristics regulating terminal voltage. Consequently, the Mvar output will vary as the system voltage varies with time, possibly drifting outside of the minimum operational limit until the output can be returned to within the band by tap-changing on the generator transformer. Therefore, the minimum operational limit must be wider that the Mvar change caused by a single tap of that transformer. This concept, and the response of the generating unit Mvar output following an event on the system, is illustrated in the diagram below:




3.2.4 It can be seen from the above diagram that the output of the generating unit may encroach the steady state capability limit, effectively "flexing" the limit for a limited period. The output will be returned to within the steady state capability limit by AVR action. Following the elapse of a period of time, action would be taken to return the output of the generating unit to within the band of the minimum operational requirement. Possible control arrangements - such as self-despatch by Generators or instructions from NGC - were considered by the sub-group.

3.2.5 The group took the view that the operational minimum requirements would be determined by the inherent operating characteristics of the generating unit and the varying system conditions that it would encounter in service. Hence the requirements would be defined functionally in the Grid Code in terms of the system conditions the plant would be required to operate under.

3.2.6 It was also noted that the consequences of non-compliance with a new standard were an important factor in its determination. In the present case, if a shortfall in performance can be offset simply by a trade-off of Mvar in the reactive market, that level of performance may not be justified as the operational minimum. On the other hand, if the shortfall creates difficulty in operating the unit at all with normal system voltage variations, or creates costs other than simple reactive contract costs (for example, constraints, insecurity or operational complexity and workload) the performance requirement would be justified.

3.2.7 Issues determining the operational minimum requirements were agreed to be:

- Voltage range at the point of connection
- Voltage fluctuations and voltage drift at the point of connection
- Excitation system response, particularly during large disturbances where it is relied on to maintain plant stability
- Automatic system controls, including protection, DAR, automatic reswitching of circuits, substations, reactive compensation and generators (intertrips), Grid Supply and Bulk Supply Transformer AVC operation.
- Reactive despatch arrangements, including the time to identify a Mvar excursion and initiate tap-changing.

3.2.8 Monitoring of system conditions and a number of computer simulations have been undertaken to quantify some of the values required for inclusion in the Grid Code wording proposals discussed later.

3.2.9 The analyses leading to the definition of requirements are described in Appendices 3b (and its appendix), 3c, 3d and 3e.

3.2.10 There was some discussion of options for reactive despatch and whether different criteria would apply for large and small voltage disturbances (Appendices 3d and 3e). One option considered was to allow generators to self-despatch to a Mvar target following small Mvar excursions although it was felt essential and in all Users' interests that NGC retained control for large disturbances, so as to manage the system securely.

3.2.11 It was felt that this would create a problem for Users of distinguishing between 'small' and 'large' disturbances which may require the Users to install some system monitoring tools. It was concluded that the most satisfactory option was to continue with all reactive despatch instructed by NGC.

# 4 Proposals

4.1 The sub-group proposes that new generating plant should be designed to meet a number of the requirements of European Standard EN 60034 - 3 (IEC 34-3) at the date of connection of that plant. This will ensure that new plant possesses at least a minimum capacity for reactive power provision (to be made available through market mechanisms yet to be developed).

4.2 The sub-group has identified the minimum operational requirements for all generating units to connect to the system such that the remainder of their reactive capability may be offered under discretionary commercial contracts to meet the needs of the system. The sub-group has not considered whether or how the commercial mechanisms might need to be changed to permit this, but a number of issues are raised in Section 5 of this report.

4.3 Proposals have been developed for appropriate revisions to the Grid Code that will enable changes to the commercial mechanisms for the procurement of reactive power, if any are required. For some issues, it may not be possible to develop revisions until the market mechanisms have been developed further. The proposals are introduced in outline below and are shown in their entirety in Appendix 4.

## 4.4 **Design Capability**

4.4.1 A major change is proposed to the paragraph in the Connection Conditions - CC.6.3.2. It is proposed that this will require all new generating units to be designed to meet the reactive power requirements of EN 60034-3 at the time of being initially brought into service, permitting a choice of value for certain parameters (subject to "back-stop" values of 0.4 for SCR and 0.9 for rated lagging power factor). These proposals represent a significant relaxation from the current requirements of the Grid Code, which require the maintenance of a defined reactive range throughout the life of the generating unit. A new term "Rated Power Factor" is proposed, such that this can be referred to in this paragraph and in various other areas of the Grid Code.

4.4.2 Wording is also included to ensure that the above provisions will apply following major work to modify or alter the generating unit.

## 4.5 **Operational Requirements**

4.5.1 The Operational Requirements are specified functionally in CC.6.3.4 and by implication in CC.6.1.7 and sections of Balancing Code No 2 dealing with Ancillary Service instructions.

4.5.2 It is proposed that CC.6.3.4 is amended to specify that the unit must be able to maintain zero Mvar, within a specified tolerance and under steady voltage conditions, over the ranges of system voltage set out in CC.6.1.4. Zero Mvar would be measured at the commercial boundary, i.e the generator transformer HV.

4.5.3 The tolerance band is necessary because of the discrete tapping of generator transformers, which are the normal means of reactive power control. Too small a dead-band would make stable control impossible; too large would reduce the precision of reactive control and thus undermine both effective system control and the management of the reactive market.

4.5.4 Ideally, the tolerance band would be specific to a unit, defined by the rating of its transformer, but this would be complex operationally. A more practical system of a few tolerance bands assigned according to generator ratings is proposed.

4.5.5 Each generating unit will require sufficient reactive capability to be able to operate within its tolerance band, handle voltage fluctuations as described in CC.6.1.7 and also handle voltage drift until NGC issues further despatch instructions.

4.5.6 All generating units will inherently provide a reactive response to large disturbances such as faults and plant trips. This cannot be prevented and in the short term - up to 3 minutes post-event[2] - intervention to reduce the response may jeopardise stability or interfere with system automatic controls. It is possible that automatic system controls during this period may restore the unit to its previous reactive output, otherwise the output will settle at a new value and corrective action can then take place.

4.5.7 Following such events NGC will issue reactive despatch instructions as soon as it is safe to do so. For units not contracted in the reactive market an instruction back to zero Mvar will be issued within 20 minutes of the event.

4.5.8 The minimum time for re-despatch is set by the 3 minute period described above and the 2 minutes specified in BC.2.8.4 for implementation. These timescales will apply for both small and large excursions outside the despatch tolerance band, since time is needed in all cases to recognise and confirm the excursion. Additional time may be needed for NGC to issue an instruction.

4.5.9 Recognising that the reactive capability required by a generating unit to meet the minimum operational requirements will now be determined in part by likely rates of change of system voltage, it is proposed to add wording to CC.6.3.4 indicating the maximum rates of change expected under normal operating conditions.

### 4.6 Other consequential changes

4.6.1 The Planning Code and the Data Registration Code require amendment to add rated Power Factor to the list of data items required by NGC.

4.6.2 CC.8.1(a) currently describes reactive power provided by generators as a Part 1 System Ancillary Service. This text will need to be modified, but it is not yet clear what type of service this will become. However, some initial draft text has been included to describe it as a "Part 2 System Ancillary Service".

4.6.3 A minor change is required to OC2.4.2.1 to reflect the changes to CC.6.3.2. Changes are required to OC5 to change the references to "testing to ensure compliance with reactive power capability being registered with NGC". The OC5 review working group will be requested to propose suitable alternative provisions.

## 5 Technical Constraints on Reactive Market Issues

5.1 The working group identified a number of areas where it may be necessary for the design of reactive market mechanisms to take account of the technical performance of generating units and constraints arising in the operation of the system.

5.2 The issues are listed below:-

- The Mvar range within the minimum operational requirement is required to permit the generating unit to be connected to the system. Consequently, Mvar output

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[2] Referenced in NGC Document ‘Technical and Operational Characteristics of the NGC Transmission System’, Issue 1 June 1998

outside that range may be considered available for discretionary contracts in a Reactive Market.

- Operation outside of the despatch tolerance band is inevitable for a period of time following an event on the system.

- It is proposed that the minimum operational requirement should be defined as a Mvar deadband around zero hv Mvar. The tighter that the minimum operational requirement is set, then the greater the amount of tap-changing necessary to remain within that band. Thus, costs may be incurred by the generator in maintaining unity power factor at the HV and these may introduce an incentive to participate in the reactive market if the maintenance costs due to tap-changing offset the Mvar costs of participating in the market.

- The operational requirement can be considered as two areas of operation:

    - Operation within the despatch deadband, in response to short-term voltage fluctuations (CC.6.1.7) and the first 5 minutes of any excursion beyond the deadband. Mvar output (and Mvarh) in this area of operation are essentially unmanageable, and, because of Mvar circulation, may be counterproductive.

    - Operation in the time more than 5 minutes after the start of a Mvar excursion but before NGC issue a despatch instruction. Output in this area is manageable by the operator and Mvarh volume can be influenced by NGC.

- It has been apparent that the current arrangements of payment for "default" Mvarh may require review to ensure that appropriate commercial incentives are available for the successful operation of the reactive market.

# 6 Compliance and Derogations

6.1 Following the proposed Grid Code modifications fewer derogations should be necessary and fewer non-compliances are expected to occur.

6.2 Derogations against CC.6.3.2 should only be necessary if permanent plant modifications are proposed that would render the plant non-compliant. It is suggested that any such derogation requests should be treated on their merits, after detailed technical examination of their impact.

6.3 Requests for derogations against operational requirements should also be rare, and would be handled by consideration of their costs and operational impact.

6.4 As discussed earlier, the operational requirements are such that a shortfall from them could not usually be overcome by means of reactive market contracts. Their effects are likely to be felt in insecurity, MW constraint costs, and operational costs and complexity of trying to manage the system around a restricted unit.

6.5 For example, a voltage range restriction may require the system voltage profile to be set to reduce circulating Mvar or even to prevent overloading of the restricted unit. This will constrain the reactive market but may also cause MW market constraints or insecurity.

6.6 A unit with insufficient reactive range to handle CC.6.1.7 voltage fluctuations or to sustain a change in voltage for 5 minutes (the minimum possible before redespatch) will be difficult to manage on the system.

6.7 There will be a continuing need for short-term reactive restrictions to be reported to NGC via re-declaration of Mvar capability, although the number of these which reduce the capability to less than the minimum operational requirements is expected to be small.

# 7 Recommendations

7.1 This report has been prepared for the Grid Code Review Panel, to fulfil the request from TUG. It is recommended that the report is forwarded to TUG with a request that development of reactive market proposals should be undertaken in the light of this report and that, if necessary, further issues should be referred back to the Grid Code Review Panel.

7.2 Although not central to the main conclusions of the report, some detailed Grid Code wording has still to be agreed. It is recommended that the Panel give further consideration to two particular issues. These are:

a. The format of the reactive redeclaration form (BC2.A.3, and Annexure 1)

b. The classification of Ancillary Services in CC8.1 and CC8.2, and the assignation of the different categories of reactive power production to these.

## Appendix 1 - Terms of Reference

The terms of reference for the Grid Code Reactive Power Review are:

1. To review the Grid Code provisions with respect to provision of reactive power, specifically Connection Conditions CC.6.3.2 and CC.6.3.4 relating to generating units, and any consequential changes elsewhere in the Grid Code.

2. To undertake an investigation to identify

    a) the implications for overall system performance of connecting new plant designed to the IEC 34-3 standard;

    b) the minimum level of performance that a generating unit and its control systems must maintain in operation.

3. To develop Grid Code wording that will

    a) enable as much of a generator's reactive capability range as is practicable to be offered under discretionary, contestable commercial contracts rather than under a Grid Code obligation;

    b) avoid imposing unnecessary costs and constraints on the electricity generation market;

    c) permit the secure, stable and economic operation of the NGC Transmission System at all times.

4. To develop Grid Code wording that clearly distinguishes between any obligations at the time of connection and the operating requirements for all plant.

5. To review the impact of the proposed new requirements on existing plant, and identify how such plant will be treated in respect of possible derogations from the proposed new requirements.

The review will be conducted by NGC, with assistance from a small sub-group of Panel members, and a report on the review will be presented to the Panel meeting in February 2001.

## Appendix 2 - Working Group Membership

The members of the sub-group were:

| | |
|---|---|
| Geoff Charter | NGC (chairman) |
| (First meeting chaired by Kevin Broadbent) | |
| David Coates | NGC |
| Nick Fee | NGC |
| John France | PowerGen |
| Nick George | TXU Europe |
| John Norbury | Innogy |

Some meetings were also attended by:

| | |
|---|---|
| Phil Bowley/Ham Hamzah | Innogy |
| Bob Nicholls/Neil Connolly | Powergen |

## Appendix 3 - Working Group Papers

The following papers were prepared for discussion at various meetings of the working group. They are reproduced in this report for completeness.

Appendix 3a - Rated Power Factor

Appendix 3b - Issues Determining Operational Requirements: Voltage Range

Appendix 3c - Issues Determining Minimum Operational Requirements: General

Appendix 3d - Issues Determining Minimum Operational Requirements: Short Term Voltage Fluctuations

Appendix 3e - Issues Determining Minimum Operational Requirements: Large Voltage Disturbances and Despatch Timescales.

Appendix 3f - *Effects of 0.4 SCR Plant on System Stability*

## Appendix 3a

**Grid Code Review Panel**

**Grid Code Reactive Review Group**

**Specification of Rated Power Factor in Initial Connection Conditions**

*Paper by David Coates, NGC*

### Introduction

1. This paper sets out NGC's views on the specification of a rated power factor in the proposed new wording of CC.6.3.2. This clause will set out initial design requirements for generating plant subject to the Grid Code.

### Discussion

2. Among the clauses in EN60034-3 pertinent to reactive power and voltage control are paras 18 and 25 defining standardised values of rated power factor. The Working Group has debated whether the revised Grid Code should specify a limiting value of rated lagging power factor as a design requirement for plant at time of connection to the system.
3. Innogy argued that such a requirement would impose unreasonable costs on generators, and also that the clause would be ineffective. This is because the values quoted in EN60034-3 may be varied by agreement between the plant purchaser and supplier, and because the Registered MW of the generating unit may exceed rated MW with a consequent reduction in available Mvar range.
4. The NGC view is that a rated power factor specification is desirable for security reasons and that it will not impose undue costs, overall, on generators. Specifically:
5. It is generally agreed that following the Grid Code review reactive services will be provided under discretionary contracts, and that plant repairs (provided operational requirements are met) will be at the commercial discretion of Generators. However, the reactive market cannot operate if there is a significant reduction in installed reactive capability. It has also been a precept of the development of the reactive market that its introduction should not lead to deterioration in security or escalation of costs to end consumers.
6. We consider that these objectives of continuity, stability of market costs and facilitation of the reactive market need to be balanced against our faith that the reactive market will provide sufficient capability. If plant is designed to operate at higher power factors than the Grid Code currently requires, the total installed reactive capability will reduce as new plant commissions and older plant closes. (See Table).

| **Rated p.f.** | **Reduction in HV Mvar capability/GW, relative to 0.85 pf** | |
|---|---|---|
| | **%** | **Mvar** |
| 0.8 | -27% | -119 |
| 0.85 | 0% | 0 |
| 0.9 | 28% | 126 |
| 0.95 | 61% | 272 |
| 0.98 | 89% | 393 |

The reduced capability would have to be made up by additional transmission investment, such as reactive compensation, and by contracts with more capable generating units.

7. The standardised values of rated power factor in EN60034-3 are 0.9, 0.85, and 0.8. It is therefore proposed to specify, as a minimum design requirement, a maximum rated lagging power factor of 0.9. Compared with the current Grid Code, this represents a significant but manageable reduction (~30%) in the required Mvar capability at time of first connection, but maintains a basic level of capability available for contract. Generators may of course choose to install plant with lower power factors where they see potential commercial benefit. Conversely, if plant deteriorates in service from its design capability, repairs would be at the commercial discretion of the generator provided operational requirements continue to be met.

8. We note the argument that Registered capacity may exceed Rated MW and that the reactive range of a unit under Reg. Cap conditions may be less than that under Rated conditions. However, this situation has pertained since Vesting. The existing Grid Code requirements have nevertheless been seen as instrumental in ensuring that enough reactive capability has been available overall to allow secure system operation. NGC believe that retention of a power factor requirement at Rated MW for initial connection, together with reactive contracts, will allow similar confidence in future.

9. We also note the argument that a requirement for a design power factor will impose unreasonable costs on generators, since reactive income cannot now be guaranteed. Generators' commercial need to maximise return on capital is incontrovertible. However, the proposed minimum requirement corresponds to one of the standardised values of rated power factor in EN60034-3 and is likely to be offered as a standard option by manufacturers. Also, generators with a reactive range seldom run for long at maximum Mvar and hence run at less than rated current for most of the time. Hence there may be consequent benefits due to fewer plant breakdowns, offsetting any additional capital costs relative to a smaller, more heavily loaded, alternator.

**Conclusion**

10. NGC consider that specifying a minimum design requirement for rated lagging power factor is important in facilitating a reactive market and guaranteeing continued security and stability of costs to end-customers. The proposal - a maximum rated power factor of 0.9, with repairs to breakdowns in service at generators' discretion - represents a significant relaxation from present requirements whilst giving the operator confidence that capability will continue to be available for contract.

11. We do not believe that the requirement will impose any significant or unreasonable additional costs on generators. Manufacturers will tend to offer EN60034-3 standard machines that meet or exceed the requirement. Where a smaller alternator might be cheaper in first cost than a 0.9 pf machine, it is likely that better reliability of the larger, less stressed, machine will offset the capital saving.

David Coates

*24 November 2000*

## Appendix 3b

**Grid Code Review Panel**

**Grid Code Reactive Review Group**

**Issues Determining Operational Requirements: Voltage Range**

*Paper by David Coates, NGC*

### *Introduction*

1. This paper describes some issues that will influence the minimum operational requirements for genset reactive power and voltage control, picking up on points raised in the Group discussion on 20 September 2000. It considers some physical characteristics of a genset connected to a network and relates these to the objectives in the Terms of Reference, particularly those of Paragraph 3.

### *Discussion*

2. Any synchronous machine is a source of e.m.f, and may be represented as a voltage source behind a synchronous reactance. Generators are also fitted with AVRs that regulate terminal voltage and are crucial to the stability of the plant under transient disturbances. It follows that changes in system load or system impedance result in changes in reactive current into or out of the machine. Genset reactive output can be altered by tapping the generator transformer or by adjusting terminal voltage, insofar as this can be done. The same processes would be used if it was desired to restore reactive output to an earlier value following a change in system voltage.
3. Paragraph 3(a) of the Terms of Reference - *'enable as much of a generator's reactive capability range as is practicable to be offered under discretionary, contestable commercial contracts rather than under a Grid Code obligation'* - implies that a non-contracted[3] generator should be able to operate at or around 0 Mvar output at its point of connection to the system. Operation of a reactive market requires that it should be possible for a generating unit to connect to a node of the transmission system where voltage control already meets quality and security standards, and operate in the MW market alone. Since generators have an inherent reactive response to system voltage changes, an operational requirement will acknowledge this response and practical methods of managing it.
4. Transmission networks are designed to operate over a range of system voltage, and the ability to control the voltage profile is extremely important to the System Operator in managing the system securely and economically. It follows that a non-contracted unit should be able to operate at zero Mvar output across the range of system operating voltages. Inability to do this may increase operating costs, increase constraints or reduce security. An illustrative example is discussed in the Appendix.
5. Controlling generator reactive output by means of the transformer tap changer, with constant alternator voltage, means that there is generally some reactive 'despatch

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[3] For the purpose of this discussion 'non-contracted' means that the unit is assumed not to have an Ancillary Service contract for reactive services, beyond the operational minimum, to aid system security.

error' due to the discrete voltage ratios of the transformer. This is acknowledged in the existing Grid Code (SDC2.4.3.5/BC2.A.2.6). Operation at 0 Mvar would therefore have to be qualified with a tolerance band, even under steady operating conditions.

6. Further departures from zero Mvar would occur due to short term voltage fluctuations, longer-term voltage changes (for example during morning load pick-ups) and larger disturbances, for example due to system faults.

***Conclusion***

7. The next stage in defining an operational requirement would be to quantify these effects, examine the practical methods of managing non-contracted units, and agree Grid Code wording that captures the requirements. The operational requirement would then set the baseline for genuinely discretionary reactive market contracts. Understanding the principles that determine the operational requirement should allow more effective and transparent handling of plant breakdowns and derogation requests in future.

David Coates

*31 October 2000*

*End*

## APPENDIX

### Grid Code Review Panel

## Grid Code Reactive Review Group

### Example of Effects of Voltage Range Restrictions

A1. Consider a cluster of interconnected generators within a section of the grid. Three generators (identified as A - C) are contracted for reactive capability and can provide this over the system operating voltage range. The System Operator is attempting to despatch lagging reactive from these units to raise system voltage locally to (say) 1.05 p.u. to support a remote part of the network.

A2. The fourth generator (D) is not contracted for reactive capability, and has a restriction on the upper voltage at which it can maintain 0 Mvar transfer to the system (the restriction could be due to a tap-changer limitation). Above this voltage, the unit is forced to absorb Mvar.

A3. Making an assumption about the generator transformer impedance (say 15% on set rating) it is possible to quantify the Mvar absorption for a given upper voltage limit.

A4. If the unit's upper voltage limit for 0 Mvar is 1.03 p.u, a system voltage of 1.05 will cause a var absorption of approximately $^{2}/_{15}$ p.u. of rated MVA, ie approx 13% on rating (eg 78 Mvar for a 588 MVA unit).

A5. This Mvar absorption will have to be provided by the contracted units, or other sources, and will increase costs and reduce the reactive support available to other parts of the network, possibly increasing MW market constraints or reducing security.

A6. If the difference between desired system voltage and the restricted unit's upper voltage limit is increased, the circulating Mvar will increase to the point where they match the physical Mvar limit of the unit (ie a thermal or stability limit). This will set an upper bound on the system voltage, further increasing operating costs and constraints. When this limit is reached the system effectively has to be despatched to manage the Mvar on the restricted unit, irrespective of other security or cost considerations.

A7. For the example quoted, this limiting voltage difference would be about 5% for a generator rated to meet the current Grid Code. For units with less Mvar capability (lower short circuit ratios or higher rated power factors), the voltage difference would be somewhat lower.

### *Conclusion*

A8. Restrictions on the voltage range over which a generating unit can maintain 0 Mvar at its point of connection will result in Mvar circulation, increased reactive and constraint costs and possible insecurity. The effect of such restrictions becomes more severe for units with lower rated Mvar capabilities. The ability to achieve zero Mvar transfer over the full range of system operating voltage is an essential operational requirement for generating plant.

## Appendix 3c

**Grid Code Review Panel**

**Grid Code Reactive Review Group**

**Issues Determining Minimum Operational Requirements: General**

*Paper by NGC*

***Introduction***

1. An earlier paper[4] started to describe the issues that would determine the operational minimum requirements for genset reactive power and voltage control. This note takes the discussion forward, picking up particular factors more explicitly and considering how they might be handled in Grid Code clauses.

***Form of Grid Code Definition***

2. There is a preference for performance requirements to be specified in a functional manner wherever possible, that is, in terms of the external factors driving the requirements. Individual plant parameters would be specified explicitly only when this is essential for system reasons or for clarity and simplicity.
3. Some of the factors that would define the functional performance are already covered in the Grid Code. The functional performance specification may therefore be spread across a number of clauses and some requirements will follow implicitly from existing Grid Code provisions. Before drafting text it is worth discussing the separate elements of the performance required and their relationship to existing Grid Code clauses.

***Voltage Range***

4. This was discussed in the earlier paper. The requirement would be for generators to be able to maintain 0 Mvar at HV, (within a reasonable tolerance) over the full range of system operating voltages. In the Grid Code, these are defined in CC.6.1.4. Hence it seems appropriate to redraft CC.6.3.4 with a reference to CC.6.1.4.

***Despatch Tolerance and Despatch Arrangements***

5. The despatch tolerance would depend on the size of a tap step. Typically, this is 1.25%. For typical transformer impedances of 15% on rating, this implies a tolerance of approximately ± 5 Mvar per 100 MW of unit rating (e.g. ±25 Mvar for a 500 MW unit).
6. The generating unit Mvar output will remain closest to zero Mvar at HV if any excursion outside the tolerance is corrected quickly. For non-contracted units this could be done by the station without reference to NGC, subject to certain safeguards.
7. The system voltage is seldom constant for long and is subject to short term fluctuations (for example, as described in CC.6.1.7) and longer term variations. A unit's Mvar output will actually vary over a wider range than the 1-step tolerance band, because of:
    i. The time to observe an excursion out of tolerance, and to initiate and complete a tap-change;
    ii. The rate of change of system voltage
    iii. The short-term variations of voltage in the interval between tap-changes.
    iv. Tapping on instruction from Wokingham will necessarily be less frequent than tapping under local station control and thus the range of Mvar variation would be

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[4] 'Issues Determining Operational Requirements' Paper by David Coates (NGC) to GCRP Reactive Review Subgroup, 30 October 2000

wider. The minimum possible time between taps would be set by the tap-changers themselves and by control arrangements at the station. Generating companies are best placed to provide information on the management of tap-changing by stations and practical timings.

***Large Disturbances***

8. Following large or rapid changes in system voltage, for example following faults, trips or switching events, AVR action is essential to ensure stability of the unit and the system as a whole. Such events will involve large or rapid Mvar excursions outside the normal tolerance band. Control actions to restore Mvar output to target will need to coordinate with system control actions to stabilise and secure the system. Such system control actions include:

   i. AVR (including response during power swings)

   ii. DAR

   iii. Automatic reactive switching (ARS)

   iv. Automatic circuit and substation reswitching

   v. Generation drops

   vi. SGT AVC

   vii. BSP AVC

9. Operators may also need to take manual actions such as real power re-despatch, demand transfer or circuit switching before it is safe to re-target Mvar, which may take up to 20 minutes.

10. Restoration of Mvar output by means of generator transformer taps will automatically involve a delay that will allow DAR and other automatic post-fault actions to complete. The timing of tapping will need to coordinate with the automatic controls in general.

11. If the timescale for re-tapping following large disturbances needs to differ from the time to respond to Mvar excursions during normal operation, the Grid Code will have to distinguish between ‘normal’ and ‘post-disturbance’ conditions, and there will have to be feasible means of distinguishing them in practice. Options might include monitoring HV terminal voltage or Mvar output and identifying significant step changes. The threshold step change will have to be agreed.

12. Alternatively, the minimum practical time to tap following small excursions may be consistent with the minimum time required following large disturbances. In this circumstance, no discrimination between ‘normal’ and ‘post-disturbance’ requirements will be needed and the same Grid Code wording will cover both conditions. The requirements may be defined in CC.6.3.4 or in the Balancing Code (BC2.5.4, BC.2.8, BC2A2.6?)

***Conclusion***

13. A number of factors have been identified that will determine the operational minimum requirements.

14. Practically, the requirement will be determined by the timing of re-tapping following small or slow excursions from a Mvar output tolerance band and by the need to coordinate with AVR action plus system automatic and manual controls following large or rapid excursions.

15. Timings can be agreed, but information on the practical operating times of generator transformer tap-changers is needed. Generating companies are best placed to provide this.

16. The operating requirement can be defined functionally but it is likely to be spread over several Grid Code clauses in the CC and BC. Requirements will also follow implicitly from other clauses in the Grid Code, eg CC.6.1.7

*David Coates*

*14 December 2000*

## Appendix 3d

Grid Code Review Panel

Grid Code Reactive Review Group

**Issues Determining Minimum Operational Requirements:**

**Short Term Voltage Fluctuations**

*(Paper by NGC)*

***Introduction***

1. The Working Group meeting on 19 December discussed the issue of the Mvar despatch tolerance to be applied to a generator nominally despatched to 0 Mvar at HV and following system voltage as it varies.

2. This parameter is important in defining the performance of a generating unit not contracted under the Mvar market (the tolerance helps define the limits of the market) but also when considering the performance of a unit with temporary technical limitations on its performance.

3. This note follows from an earlier paper[1], covering one of its topics in more detail. It concentrates on slow voltage variations and more rapid fluctuations of small magnitude, such as would be encountered under normal operating conditions. The issue of performance following large disturbances (faults, trips, and major switching events) is to be addressed separately.

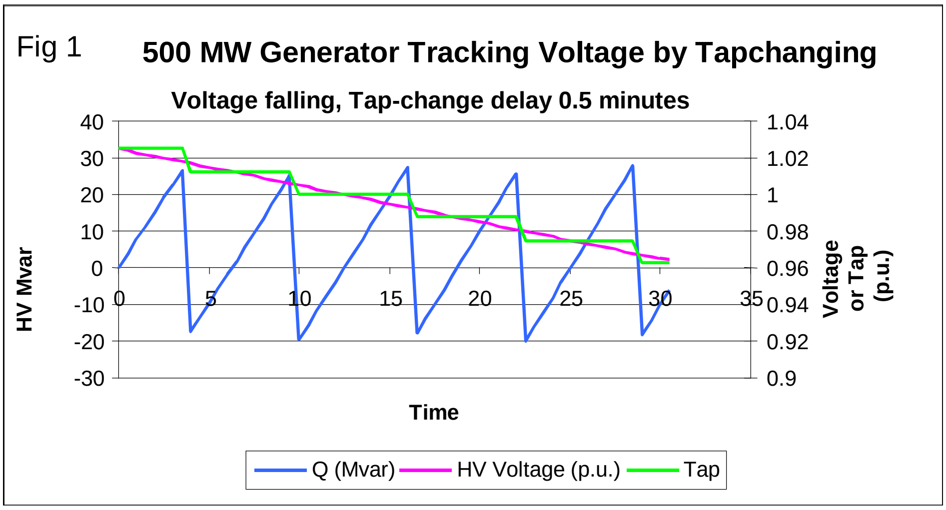
***Voltage variations and Mvar Deadband***

4. With discrete tap steps achieving exactly 0 Mvar at HV will only be possible when the ratio of HV voltage to (regulated) alternator terminal voltage exactly matches the transformer turns ratio. Otherwise there will be some Mvar despatch error but while the system voltage is constant this will be contained within a Mvar deadband determined by the size of the transformer tap step.

5. The dead band can be calculated from the rating, impedance and tap step of the generator transformer. For a typical 500 MW unit, with a tap step of 1.25%, the Mvar deadband would be about 50 Mvar, i.e. the despatch tolerance would be ± 25 Mvar.

6. If the system voltage varies, generator Mvar output will change and eventually fall outside the deadband and a tap-change will be called for. Since tap changing cannot be instantaneous, the Mvar output will exceed the deadband by an amount determined by the tap-change delay time and the rate of change of voltage.

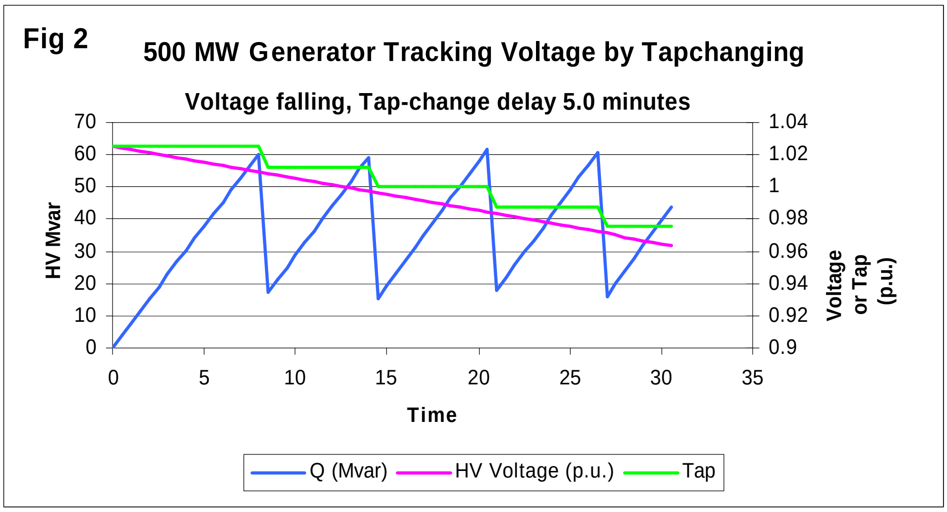
Fig 1



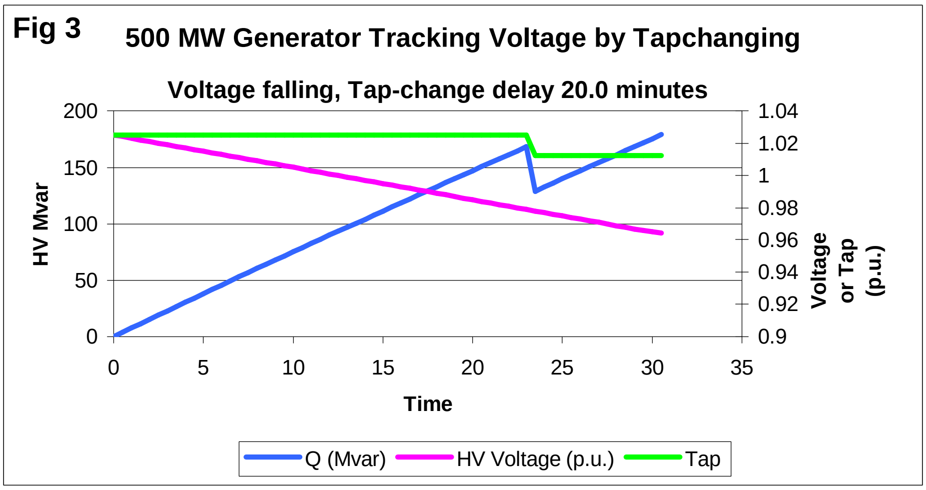

1 'Issues Determining Minimum Operational Requirements' Paper by NGC, 14 December 2000

7. Fig 1 illustrates the effect for a steadily falling voltage (magenta line) with tap changing shortly after (0.5 min) the generator (HV) Mvar output moves outside a ± 25 Mvar deadband[2]. In this example the system voltage is falling at 0.2% per minute[3].

8. If the time to recognise a Mvar excursion and implement a tap-change is increased, the Mvar output will continue to change until the tap-change is completed (Fig 2).




9. The need to recognise and confirm a Mvar excursion suggests that it may be sensible to agree a minimum time delay before tap-changing is allowed to occur. For large Mvar excursions (such as would follow system faults) this will need to be long enough to allow power swings to settle, operation of DAR, auto switching and manual actions to re-secure the system. This would be the subject of a separate paper. For smaller, slower, changes 1 to 2 minutes may suffice. Intervals between tap-changes will be at a minimum if generators self-despatch, ie avoiding the delay while NGC register the need for a tap-change and issue an instruction. Considerations of system security, particularly after large disturbances, and system control under emergency conditions may preclude self-despatch. However, it is interesting to consider it as part of an exercise to explore the factors determining minimum Mvar range.




10. If tap changing is very slow it may not keep pace with the changing voltage and the genset reactive output will drift further and further from zero (Fig 3). Multiple

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[2] In this simple illustrative model the generator is assumed to be connected via its transformer to an infinite busbar whose voltage determines the Mvar output of the unit. The alternator terminal voltage is assumed to be held constant by its AVR.

[3] This is believed to lie towards the upper end of the range of rates of smooth voltage variation likely to be sustained for a period of minutes or more. More rapid fluctuations are likely to be of short duration.

tapchanges in close succession (if feasible) would be needed to bring the output back within the deadband.

11. Voltage can of course vary over a wide range and at any rate. Large sudden excursions may be caused by plant trips or system faults and subsequent generator control must be managed to coordinate with DAR and automatic and manual actions to resecure the network.

12. However, small sudden disturbances may occur at any time and generating plant, like the rest of the system, will be designed and managed to cope with these.

13. Isolated or infrequent voltage changes may cause the generator Mvar to exceed the 1 tap deadband but this can readily be corrected by tap-changing. More frequent or repetitive voltage variations may be caused by fluctuating system loads and it may not prove possible to manage these by tap-changing. Grid Code CC.6.1.7 defines the maximum repetitive voltage step-change at a point of common coupling as 1%. Such voltage changes may occur up to several times per minute without infringing the flicker limits of Engineering Recommendation P28. The effects of such voltage changes on a genset's Mvar output can be illustrated for conditions where the duration of the steps is less than the minimum time between taps (Fig 4) and where tapping during the voltage step an be achieved (Fig 5). In both cases the starting conditions are such that the generator is near the top of its ±25 Mvar steady state deadband. In the illustrations the step changes are not shown as true steps; this is due to the method of plotting the charts and does not affect the conclusions.

Fig 4

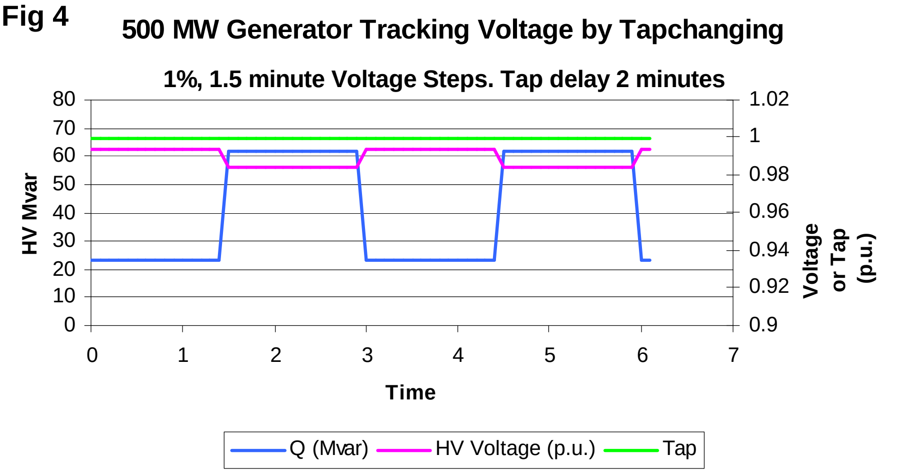
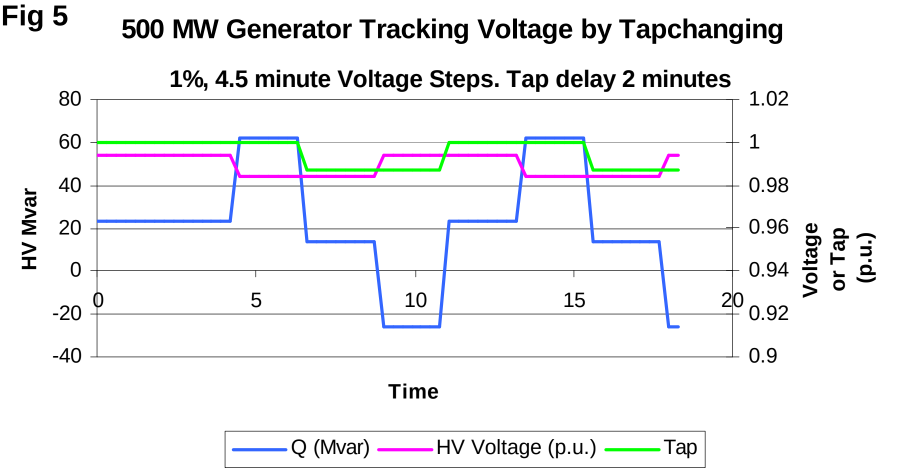



Fig 5




14. In the example of Fig 4, the voltage variation causes repeated excursions of Mvar output from the initial value of 23 Mvar to 62 Mvar. In Fig 5 the voltage steps are of

longer duration, allowing time to tap-change between voltage steps. The result is that the Mvar output swings outside the 1-tap deadband in both directions. Repetitive tap changing would occur, but the generator Mvar output nevertheless swings over a range of some 88 Mvar (approx 18% of rated MW). Since both positive and negative voltage step-changes need to be accommodated, with the generator starting at either extreme of its ± 25 Mvar despatch tolerance, the total Mvar capability range required would be ± 62 Mvar, ie approximately ± 13% of the Rated MW. This happens to correspond approximately to the Mvar range covered by a generator subjected to a 0.2%/minute voltage ramp (see the earlier examples) with a 5 minute delay to tap-change.

15. Voltage fluctuations thus imply Mvar output variations beyond the 1-tap deadband achievable in steady-state conditions, even if corrective tap-changing is applied. A narrow Mvar deadband and short time delay to tap will result in frequent tap-changing. If this is of concern, the frequency of tap-changing may be managed by widening the deadband or increasing the tap-change delay.

16. The effects can be seen in Figs 6 - 8, which illustrate the effect of applying an actual 24-hour voltage trace recorded at an NGC site to the HV busbar in the illustrative model.

Fig 6

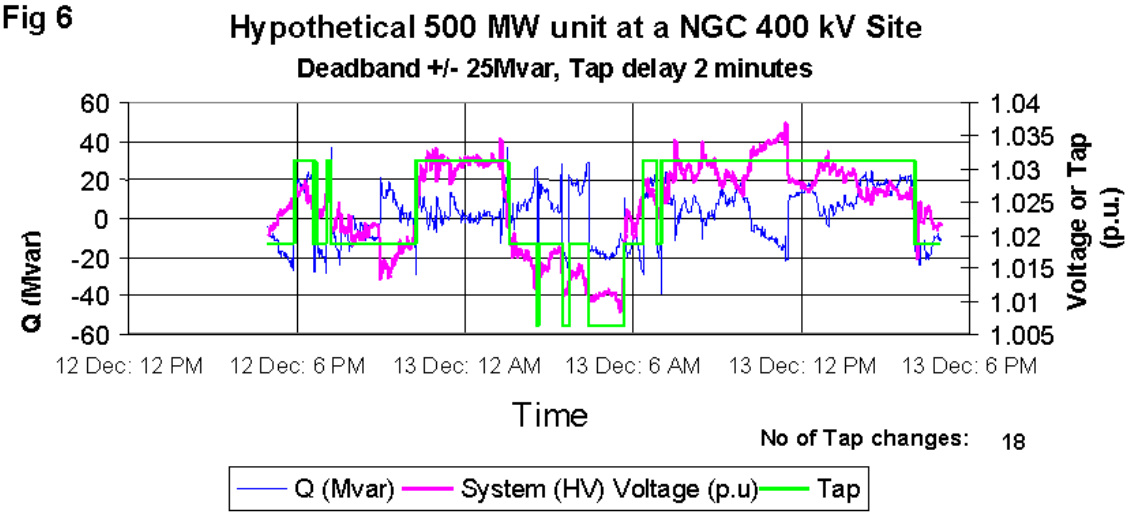



Fig 7

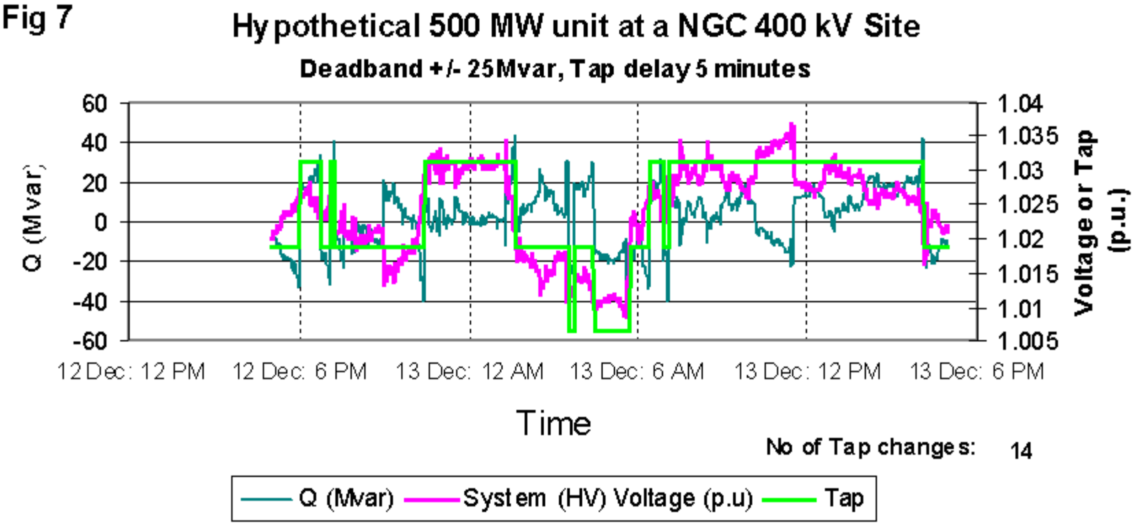
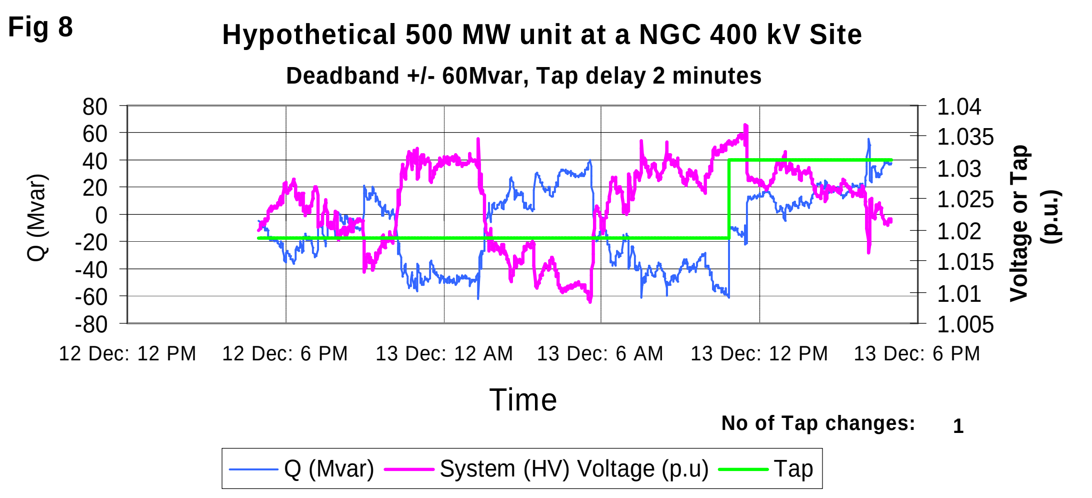


Fig 8




Different voltage variations would occur on different days and result in different numbers of tap operations.

### *Shortfalls, Breakdowns and Derogations*

17. A generating unit that lacks the continuous Mvar capability to achieve a 1-tap deadband (in the illustrative example this would be ± 25 Mvar) would be very difficult to manage. In effect, the voltage of the transmission network would have to be tightly controlled (by means of other gensets and NGC equipment) to micro-adjust the genset Mvar output to remain within its restricted range. This may not be feasible in all circumstances; where it is, it is likely to be expensive in terms of constraints and reactive uplift. The acceptability of plant so restricted (or the issue of a derogation) would depend on the feasibility and costs of managing the system with the plant connected.

18. Long delays in tap-changing, as in Fig 3, will increase circulating Mvar. Temporarily, the delay will have the same effect as a tap-range restriction as discussed in an earlier paper[4]. The consequences could include increased Reactive Power Uplift costs due to circulating Mvar, or increased constraint costs or reduced security as the system is managed to cope with the restricted unit. Permanent tap-range restrictions would be regarded as major non-compliances; very slow tap-changing may be as serious.

19. It should be noted that in neither of these cases is a solution to the plant restriction obtainable simply by meeting a system 'Mvar requirement' from a different source. The issue is the feasibility and cost of managing the system to cope with the requirements of the restricted unit. Costs may arise from Mvar circulation, MW constraints, insecurity and control room workload.

20. If the Mvar deadband were wider than the 1-tap range discussed earlier, the system effects of non-compliance would be less serious. If a genset were capable of only ± 50 Mvar say, against a deadband of ± 60 Mvar, the immediate effect would be to increase the frequency of tap-changing on that genset. The implications for managing the power system as a whole would be quite small, apart from the possible need to procure an additional 10 Mvar (or equivalent) of reactive capability. The generator thus feels the technical consequences of this 'non-compliance', and the system impact may be handled through the reactive market. A Grid Code requirement for a Mvar range wider than that implied by the 1-tap deadband and a reasonable time to tap is thus difficult to justify as a minimum operational requirement.

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[4] 'Issues Determining Operational Requirements' Paper by David Coates (NGC) to GCRP Reactive Review Subgroup, 30 October 2000

### *Conclusion*

21. Under steady state conditions, with constant alternator terminal voltage, the genset Mvar output cannot be held at exactly zero Mvar at HV. The tap step size and impedance of the generator transformer set a minimum deadband. For typical generator transformers in current use, the deadband in Mvar is equivalent to about 10% (or ± 5%) of the rated MW. (e.g. ± 25 Mvar for a 500 MW unit).

22. The deadband may be specified in percentage terms, or perhaps more simply as a set of Mvar ranges applicable to generators of particular ranges of ratings. Several bands may be required: since the deadband is likely to set the baseline for reactive market contracts, a wide deadband for a small unit will exclude much of that unit's reactive range from the market.

23. Voltage does not stay constant and is subject to long-term changes (over several minutes or hours) and shorter-term fluctuations that will take the generator Mvar outside the 1-tap deadband. For the slower changes, the extent to which this occurs depends on the rate of change of voltage and the time delay in recognising, and confirming, the Mvar excursion and implementing a corrective tap-change.

24. Short-term voltage fluctuations as described in CC.6.1.7 will also cause Mvar excursions outside the 1-tap deadband. For step-changes, speed of tap-changing will not affect the size of the excursions but faster tap-changing will reduce the Mvarh volume. With a control deadband equivalent to one tap step, voltage step changes of 1%, as specified in CC.6.1.7 imply Mvar changes over a range of approximately 18% of rated MW (e.g. 88 Mvar for a 500 MW unit with a ± 25 Mvar deadband). The Mvar capability range needed to accommodate such changes would be ± 13% of Rated MW, (e.g. ± 65 Mvar for a 500 MW unit). This is comparable to the Mvar range arising from a voltage changing steadily at 0.2% per minute with a 5 minute tap changer delay.

25. Minimum Grid Code operational requirements to handle steady-state voltage, slow voltage changes and small magnitude fluctuations might thus be summarised as:

    - Over the normal voltage ranges and rates of change of voltage specified in CC.6.1.4, any such **Generating Unit** must be capable of maintaining 0 Mvar at its **Point of Connection**, within a tolerance of ± *5 Mvar per 100 of* **Rated** MW when the system voltage is constant. *[Alternatively, this could be defined as bands: ± XMvar for gensets with Rated MW up to A MW, ± Y Mvar for gensets with Rated MW between A and B MW, etc]*.
    - *If generators were to self despatch:* When system voltage is subject to variations, Mvar excursions outside the tolerance band shall be corrected within not less than 3 minutes and not more than 5 minutes.
    - *Otherwise, if NGC issue despatch instructions:* The existing wording of BC2.A. 2.6 regarding Mvar output instructions will apply.
    - Voltage fluctuations as defined in CC.6.1.7 may occur at the point of connection of the generating unit. The generating unit must cope with such fluctuations and neither NGC nor any User shall be required to take action to reduce such fluctuations to enable the generating unit to connect or remain connected.

26. Actions required following large voltage disturbances will be discussed in a separate paper.

*David Coates*
*17 January 2000*

**Appendix 3e**

**Grid Code Review Panel**

**Grid Code Reactive Review Group**

**Issues Determining Minimum Operational Requirements:**

**Large Voltage Disturbances and Despatch Timescales.**

*Paper by NGC*

### *Introduction*

1. Previous papers have discussed issues determining minimum operational requirements in general, and voltage range and small or slow voltage variations in particular. This note considers the requirements relating to large disturbances, and links these to the control timescales relating to small or slow voltage variations

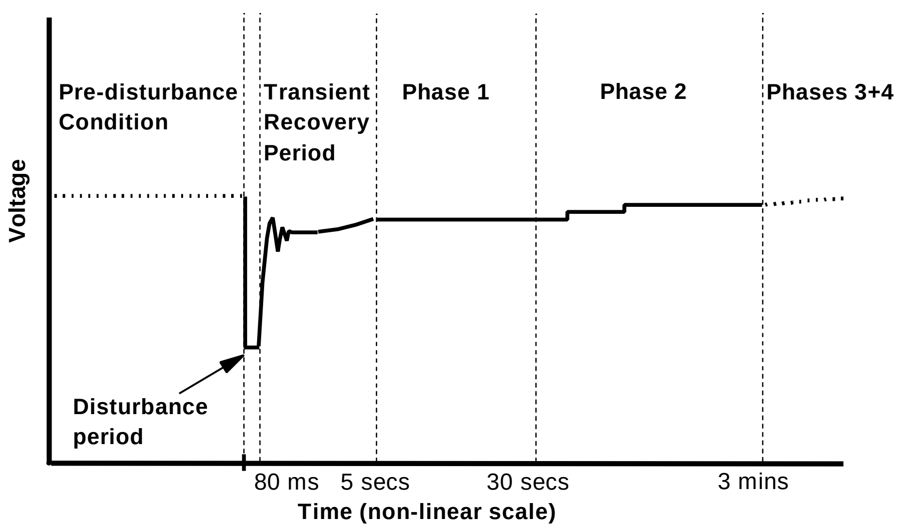
### *Definitions*

2. The voltage response to a system disturbance can be divided into a number of time-phases. These are described in the NGC publication *'Technical and Operational Characteristics of the NGC Transmission System'* , from which the following definitions and indicative durations are extracted.

| Indicative time from disturbance | Time phase |
|---|---|
| n/a | Disturbance period (e.g., fault condition) |
| 0-5 secs | Transient Recovery Period (TRP) involving the decay of high frequency transients (200 Hz - 10 kHz) and fast AVR action on generators and SVCs |
| 5-30 secs | Phase 1 : Post TRP, including delayed auto-reclose (DAR) action |
| 30-180 secs | Phase 2 : Automatic action phase (e.g., auto-switching including automatic reactive switching, auto-tapchange) |
| 3 - 20 mins | Phase 3 : Manual action phase (e.g., manual switching & tapchange) |
| >20 mins | Phase 4 : Sustained condition |

A typical voltage response to a short-circuit fault, in which these time phases are indicated, is shown below:

**Typical Voltage Response to a Short-Circuit Fault**



3. The behaviour required of a generating unit, and the control actions that may be taken, can be discussed in the context of these time phases following a major system disturbance.

***Technical Requirements***

*Disturbance period and Transient Recovery Period (0 - 5 seconds)*

4. During the first 5 seconds following a disturbance uninhibited AVR action is required to guarantee stability. Reactive power output of the set during this time will be driven by the system voltage (which may vary over a wide range), and by the excitation response required to maintain stability. Control actions in this time phase to manage reactive output to commercial targets are likely to jeopardise stability.

*Phase* 1 (5 - 30 seconds)

5. The significant activity during this period is the operation of Delayed Auto Reclose schemes. For fleeting faults this will involve restoration of sound circuits so that, after an initial disturbance, generator Mvar output may return close to pre-fault levels. For permanent faults, DAR will re-apply the fault several seconds after the original event, so a further disturbance period and TRP will ensue.

6. Intervention to control Mvar output during this time-phase is unnecessary in the case of fleeting faults and undesirable for permanent faults. The possibility of these means that Phase 1 includes the potential for a repetition of the disturbance and TRP phases, so the same requirements for reactive management and uninhibited AVR action will apply throughout the Disturbance Period, TRP and Phase 1.

*Phase* 2 (30 - 180 seconds)

7. During this time phase a number of automatic control operations occur throughout the power system. These include automatic tap-changing of Grid Supply Transformers and distribution transformers, automatic switching of reactive compensation plant and automatic re-switching of substations and circuits.

8. The sequence of automatic controls has been developed, in terms of overall principles and in application at specific sites, to maximise security margins, minimise risks of voltage collapse or instability and to minimise disturbance to customers. Apart from the magnitude of voltage steps, ill-coordinated controls can lead to ‘double bumps’ in customer voltage, for example due to voltage restoration by one control being followed by further voltage disturbance as a second control operates.

9. The effect of these controls is to change the reactive output of generators as they run through their operating sequence. Hence attempts to change generator Mvar during this time-phase may prove counterproductive as the final position to be corrected will not be known until late in the period. Also, adverse interactions with the system automatic controls may increase disturbances to customers or reduce security.

10. If Mvar output is to be changed by tap-changing following a disturbance it will take most of Phase 2 (at least) to confirm that a disturbance has occurred and to establish the final level of Mvar output to be corrected. High Mvar outputs during this short period, if contained within the overcurrent envelope specified in EN 60034-3, are unlikely to incur significant costs to generators whilst attempts to reduce them during this time-phase would risk adverse system effects and/or control complexity.

*Phase* 3 (3 - 20 minutes)

11. Once automatic controls have run through, manual control of the system starts. At this point, gensets that have permanently departed from their pre-disturbance reactive output will be identified and tap-changing can commence. For small disturbances this could be by independent action by generators or under instruction from NGC. For large disturbances, NGC may need to take further manual actions to secure the system

before it is safe to change taps. The difficulty of then distinguishing between 'small' and 'large' disturbances implies that it would be prudent for all reactive despatch to be on instruction from NGC, as is the current practice.

### *General Reactive Despatch Process*

12. From the above, and from the discussions in previous subgroup papers, it is possible to develop a general process for Mvar control and despatch for generation not contracted in the reactive market. This process would determine the lower limits of the market, in terms of plant performance, and the minimum operational requirements for plant to remain connected.

13. Under steady voltage conditions, gensets must achieve their Mvar despatch targets (e.g. zero for non-contracted units) within a despatch tolerance set by a typical generator transformer tap step. For a transformer with impedance 15% on rating and step size of 1.25% of nominal voltage, the tolerance would be ±5% of the rated MW (e.g. ± 25 Mvar for a 500 MW unit.

14. Following any excursion outside this band, due to steadily or suddenly varying system voltage, a period of 3 minutes (i.e. up to and including Time-Phase 2) is required to establish that the Mvar change is permanent before a re-despatch action is initiated. A further 2 minutes (in line with current practice) is then required for implementation. This applies for disturbances of any magnitude.

15. Hence the minimum possible time between tap instructions is 5 minutes. In practice, a period of time will elapse between the initial 3 minutes and the implementation period while NGC issue a despatch instruction, and a further delay may be needed following a large disturbance while NGC resecure. NGC would normally issue an instruction within no more than 20 minutes of the excursion.

16. Mvar excursions outside the despatch tolerance band may be considerable, but infrequent, for faults or other large disturbances. Smaller, but repeated, excursions would occur during periods of continuous voltage drift or short-term voltage fluctuations such as those described in CC.6.1.7.

17. An earlier paper[1] estimated the Mvar range necessary for a genset to handle 1% voltage step changes as specified in CC.6.1.7, in addition to the despatch tolerance deadband. For a given sequence of 1% voltage steps the Mvar swing would be approximately 18% of Rated MW, with a maximum excursion in either the lead or lag direction of some 13%. (i.e. a 500 MW machine would swing between -23 Mvar and 65 Mvar, or between 23 Mvar and -65 Mvar). The total envelope to accommodate both positive and negative steps would thus be ±13% of Rated MW.

18. The Mvar excursions due to a drifting or ramping voltage will depend on the rate of change of voltage as well as the time elapsed in recognising the Mvar excursion and implementing a tap-change. For a minimum elapsed time of 5 minutes as discussed above, the Mvar range needed to cover 1% voltage step changes (±13% of Rated MW, as above) would be consistent with a system voltage changing at about 0.2% per minute.

19. There may be value in quoting typical rates of change of system voltage (perhaps averaged over given time periods) in the Grid Code for the guidance of users, subject to sufficient raw data being accessible.

### *Conclusion*

20. For the first 30 seconds after a major system disturbance, genset excitation systems will act to control terminal voltage and maintain generator stability. Attempting commercial management of reactive power in this period may jeopardise stability.

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[1] Issues Determining Minimum Operational Requirements: Short Term Voltage Fluctuations. Paper to CCRP Subgroup 4 January 2001

21. During Phase 2 (30 to 180 seconds post-disturbance), automatic system controls will be acting to re-switch the network and tap transformers to maintain security and restore customers' voltage. Genset reactive output will vary as a consequence but will settle towards the end of the period. Intervention to manage reactive output may interfere with the action of the automatic controls, reducing security and increasing disturbances to customers.

22. Automatic control action, including DAR during the initial 30 seconds, may restore genset Mvar output to its original value. Otherwise, the Mvar output will settle to a new value towards the end of the period.

23. After the automatic control time-phase the need for any Mvar re-despatch can be confirmed and the amount of adjustment will be known. This will be true for both major system disturbances and for Mvar excursions due to voltage drift or small voltage fluctuations.

24. For large disturbances NGC may need to assess system security and take further remedial action before it is safe to re-target generator Mvar. Since it may be difficult in practice to distinguish 'small' and 'large' disturbances within a short timescale, it appears preferable that all Mvar re-despatch should remain under instruction from NGC, as now.

25. The minimum time to re-despatch Mvar following any excursion or disturbance is thus: 3 minutes (to allow for automatic control actions and to confirm the need to re-despatch), 2 minutes to implement (as per current Grid Code), and whatever time is needed for NGC to assess the situation and issue despatch instructions.

26. The minimum Mvar range needed by a generating unit to operate will be determined by the need to handle short term voltage fluctuations as set out in CC6.1.7 and by the need to track changing system voltage with a minimum of 5 minutes between tap operations. Generally this time interval will be longer since NGC will have to recognise a need to redespatch and issue despatch instructions. Large system disturbances, although infrequent, will require uninhibited AVR response, up to the gensets design MVA limit for at least 3 minutes following the disturbance and up to 20 minutes, while NGC resecures the system and issue despatch instructions.

*David Coates*
*16 January 2001*

**Appendix 3f**

**20 January 2001**

## Generator Grid Code Connection Conditions Review.

## Note on Transient Stability Implications of Reducing Short Circuit Ratios to 0.4

*(Paper by NGC)*

### Introduction

1. This note summarises some generic work done within NGC on the effects of reducing generating unit short circuit ratios from the current Grid Code requirement of 0.5.
2. Reduced values of SCR down to as low as 0.22 were studied; however the value of 0.4 was selected for particular investigation. This was because for nearly all the sizes of generators connecting to the NGC system, 0.4 is the minimum value allowed in the international standard EN 60034-3. In the present review of generator Grid Code connection conditions, the suggestion is that CC 6.3.2 should be changed to require that generators connecting to the NGC system should comply with EN 60034-3 in respect of lagging power factor, overcurrent requirements and SCR (subject to a minimum value of 0.4). Results for lower values of SCR are presented as sensitivity cases where appropriate.

### Summary of Investigations and Results

3. The first study examined the effect on stability of changing the SCR at an electrically remote generating station in a current system configuration. For illustrative purposes, Sizewell B was chosen as the station for study.
4. Conditions representing a Summer weekend plateau were studied by investigating the effect of a three phase balanced fault at the Twinstead Tee section, resulting in the post fault outage of the Sizewell-Pelham and Bramford-Braintree Tee-Rayleigh 400 kV circuits. The response of the generators at Sizewell B was investigated for three conditions.
   - 4.1. Sizewell B alone changed to an SCR of 0.4.
   - 4.2. All machines in England and Wales, including Sizewell B, changed to an SCR of 0.4.
   - 4.3. All machines in England, Scotland and Wales, including Sizewell B, changed to an SCR of 0.4.
5. The results were compared with a base study with no change. This showed a maximum first swing angle of $34^0$ and adequate damping at the Sizewell B machines.
6. Changing the Sizewell machines alone gave a slightly higher first swing of $35^0$, and subsequent oscillations were adequately damped.
7. Changing all the generators in England and Wales displayed a smaller first swing ($31^0$) and slightly improved damping.
8. Changing all generators in England, Wales and Scotland resulted in an improved first swing of $25^0$, but the damping had deteriorated.

9. Investigation of the machine slip showed that when all machines are changed in England, Wales and Scotland, the slips increased, implying that the total system movement had increased.

10. The next set of studies modelled a summer weekend plateau in a later year and considered the effect of adding additional generic generating units connected at Sizewell 400kV, effectively doubling the export from the location. This provided examples both of the effect of a large isolated generation group and of a group where some units meet the current Grid Code whilst others have lower SCRs. The network also included several new CCGT stations, and the effect of reducing SCRs of this new plant only was considered (i.e. Sizewell B and all existing generators were modelled with their actual current parameters). The response of the system to the Twinstead Tee fault was investigated.

11. The response in the base case (no SCR changes) showed a first swing response of $60^0$ and the damping was good because of the use of power system stabilisers on the new units connected at Sizewell and the new CCGT stations. Two conditions were studied:

    11.1. The SCR of the additional Sizewell generators only was changed to 0.4.

    11.2. The SCRs of all new CCGT generators as well as the additional plant at Sizewell were changed to 0.4.

12. Changing only the extra Sizewell generators to an SCR of 0.4 showed a large increase in first swing response to a marginally stable $85^0$. A further decrease in SCR to 0.39 resulted in instability.

13. When all new generators' SCR were changed to 0.4, the first swing was $74^0$, but further reduction to a SCR of 0.39 gave a marginally stable first swing response of $85^0$.

14. A further set of studies was carried out using a network representing a summer weekend plateau. In this case the fault was applied at Strathaven on the Scottish interconnectors. The system was set up so that stability was marginal in the case with unmodified SCRs, with a first swing of $80^0$. Three conditions were studied:

    14.1. Change SCRs of all generators in England and Wales to 0.4.

    14.2. Change the SCRs of all generators in England, Wales and Scotland to 0.4.

    14.3. Change the SCRs of all generators in Scotland to 0.4.

15. Reducing SCRs on all the generators in England and Wales gave a small improvement in first swing and damping, whereas changing all the generators in England, Wales and Scotland produced instability. Furthermore reducing SCRs in Scotland alone also produced instability.

**Conclusions**

16. The results with new 0.4 SCR units alongside the existing Sizewell B plant indicate that reducing the SCR of one station in an area where other units meet the current Grid Code will have a de-stabilising effect. This would be similar to the conditions when the first few generators designed to EN60034-3 are connecting.

17. The results with the additional generation at Sizewell when generators in the rest of England and Wales have reduced SCR indicate that the stability would be improved,

although there is a hint that the damping might be worsened. However the use of PSS on the new units could cure this.

18. Indications are that SCR reduction of generation in England and Wales will not have a detrimental effect on Scotland. However, reducing SCRs of the generation in Scotland may reduce stability margins, with or without SCR reduction on the units in England and Wales.

19. It appears that reducing SCRs of several units in an area causes the system as a whole to accelerate more as a result of a fault along with the faulted generation. This reduces the angle between the faulted generation and the rest of the system, and helps to maintain synchronism. This may be at the expense of a reduction in the damping, but PSS should assist this. However reducing SCR on a very few sets in an area may reduce margins because the internal angles within these generators becomes larger with respect to the surrounding generation, and a fault close to these units can therefore more easily result in instability.

20. As a general conclusion, these results indicate that when faults occur that leave a large system and a smaller subsystem weakly connected, then:

    - Reducing SCRs in the small subsystem tends to reduce transient stability margins;

    - Reducing SCRs in the large subsystem tends to improve transient stability margins

21. Reducing SCR may worsen damping in multi-machine systems, and the effect would need to be monitored.

22. It is emphasised that these were generic studies considering a limited set of system conditions. Several of these cases were set up to show the system in a stressed state, with stability already marginal before SCRs were reduced. SCR is only one of a number of parameters that influence system stability (others include inertia constant, machine and transformer reactances, and the excitation system). Units with the same SCR may differ markedly in one or more of these other parameters.

23. Even with plant parameters changed in a simple way, as was done in these studies, the overall effects on system stability are complex. In some cases the effects of reducing SCR are destabilising, in others the effect is neutral or even mildly helpful to stability. Overall the evidence against a minimum SCR of 0.4 is not strong and a general reduction from the existing Grid Code requirement can be countenanced, with any local stability issues being resolved on a case by case basis.

# Appendix 4 - Proposed Grid Code Modifications

The following extracts are based on the Grid Code Issue 2 as approved for implementation at the NETA Go-Live Date.

## 1. Glossary & Definitions Extracts

| | |
|---|---|
| **Rated Power Factor** | The "rating-plate" power factor of a **Generating Unit**, being the minimum lagging power factor at which the **Generating Unit** was designed to operate at **Rated MW** output. |
| [ [2]**Part 3 System Ancillary Services** | **Ancillary Services** which are required for **System** reasons and which are provided by a **User** under an **Ancillary Services Agreement.]** |
| **System Ancillary Services** | Collectively **Part 1 System Ancillary Services** ~~and~~, **Part 2 System Ancillary Services** and **Part 3 System Ancillary Services**. |

## 2. Planning Code Extracts

PC.A.3.3 Rated Parameters Data

PC.A.3.3.1 The following information is required to facilitate an early assessment, by **NGC**, of the need for more detailed studies;

(a) for all **Generating Units**:

Rated MVA
**Rated MW**
**Rated Power Factor**
Direct axis transient reactance;

(b) for each synchronous **Generating Unit**:

Short circuit ratio
Inertia constant (for whole machine), MWsecs/MVA;

(c) for each **Generating Unit** step-up transformer:

Rated MVA
Positive sequence reactance (at max, min and nominal tap).

This information should only be given in the data supplied with the application for a **Master Connection** and **Use of System Agreement** and **Supplemental Agreement** or for a new or varied **Supplemental Agreement** (if appropriate for the variation), as the case may be.

[2] This is to be the subject of further consideration

…………….

PC.A.5.3 Synchronous Machine and Associated Control System Data

PC.A.5.3.1 The following **Generating Unit** and **Power Station** data should be supplied:

(a) **Generating Unit** Parameters

Rated terminal volts (kV)
* Rated MVA
* **Rated MW**
* **Rated Power Factor**
* Minimum Generation MW
* Short circuit ratio
Direct axis synchronous reactance
* Direct axis transient reactance
Direct axis sub-transient reactance ……………
Direct axis short-circuit transient time constant.
Direct axis short-circuit sub-transient time constant.
Quadrature axis synchronous reactance
Quadrature axis sub-transient reactance
Quadrature axis short-circuit sub-transient time constant.
Stator time constant
Stator leakage reactance
Armature winding direct-current resistance……………..

## 3. Connection Conditions Extracts

Grid Voltage Variations

CC.6.1.4 Subject as provided below, the voltage on the 400kV part of the **NGC Transmission System** at each **Connection Site** with a **User** will normally remain within ±5% of the nominal value unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail. Voltages on the 275kV and 132kV parts of the **NGC Transmission System** at each **Connection Site** with a **User** will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail. At nominal **System** voltages below 132kV the **NGC Transmission System** at each **Connection Site** with a **User** will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, voltage may collapse transiently to zero at the point of fault until the fault is cleared.

**NGC** and a **User** may agree greater or lesser variations in voltage to those set out above in relation to a particular **Connection Site**, and insofar as a greater or lesser variation is agreed, the relevant figure set out above shall, in relation to that **User** at the particular **Connection Site**, be replaced by the figure agreed.

…………………………..

Voltage Fluctuations

CC.6.1.7 Voltage fluctuations at a **Point of Common Coupling** with a fluctuating **Load** directly connected to the **NGC Transmission System** shall not exceed:

(a) 1% of the voltage level for step changes which may occur repetitively. Any large voltage excursions other than step changes may be allowed up to a level of 3% provided that this does not constitute a risk to the **NGC Transmission System** or, in **NGC's** view, to the **System** of any **User**.

(b) **Flicker Severity (Short Term)** of 0.8 Unit and a **Flicker Severity (Long Term)** of 0.6 Unit, as set out in **Engineering Recommendation** P28 as current at the **Transfer Date**.

…………………………..

~~**Plant** Performance Requirements~~ [*Heading moved below* ]

CC.6.3.2 ~~All **Generating Units** must be capable of supplying rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the **Generating Unit** terminals. The short circuit ratio of **Generating Units** shall be not less than 0.5.~~

Each **Generating Unit** must meet the requirements of **European Specification** EN 60034-3, in respect of:

(a) short circuit ratio, subject to the value being no less than 0.4;

(b) overcurrent requirements; and

(c) **Rated Power Factor,** subject to the value being no more than 0.9 lag,

at its **Completion Date**, unless other values are agreed with **NGC** in accordance with the provisions of **European Standard** EN 60034-3. The relevant version of **European Specification** EN 60034-3 is that version current at the time when the **Generating Unit** is designed or the date of signing the **Supplemental Agreement**, whichever is later.

In the event of any modification, or alteration, to the **Generating Unit** the above requirements of **European Specification** EN 60034-3 and specified maximum and minimum values must be met at the **Completion Date** following any such modification or alteration. The relevant version of **European Specification** EN 60034-3 is that version current at the time when the modification, or alteration, was designed or the date of signing the modified **Supplemental Agreement**, whichever is later.

Any options chosen from within **European Specification** EN 60034-3 shall be notified to **NGC** in accordance with PC.A.3.3.1 and will be recorded in the **Supplemental Agreement**.

The above requirements shall apply over the range of terminal voltages and frequency set out in **European Specification** EN 60034-3.

**Plant** *Performance* Requirements

CC.6.3.3 Each……………………..

CC.6.3.4 The **Active Power** output under steady state conditions of any **Generating Unit** directly connected to the **NGC Transmission System** should not be affected by voltage changes in the normal operating range specified in paragraph CC.6.1.4. The voltage at the **Point of Connection** will normally change at a rate no greater than 0.2% per minute over any 5 minute period or 0.1% per minute over any 15 minute period, unless abnormal conditions prevail. Over the normal voltage ranges specified in CC.6.1.4 and under steady state voltage conditions, any such **Generating Unit** must be capable of maintaining 0 Mvar at the **Grid Entry Point** (or onto the **Users System** at the **User System Entry Point** in the case of an **Embedded Power Station)**, within a tolerance as set out in that table below, at any point in its operating range.

| **Rated MW** of **Generating Unit*** | Tolerance, Mvar |
|---|---|
| =200 | ±10 |
| >200 - =400 | ±20 |
| >400 - =500 | ±25 |
| >500 | ±33 |

* In the case of a **CCGT Module**, the sum of the **Rated MW** of the constituent **Generating Units**.

……………………..

## CC.8 ANCILLARY SERVICES

### CC.8.1 System Ancillary Services

The **CC** contain requirements for the capability for certain **Ancillary Services**, which are needed for **System** reasons ("**System Ancillary Services**"). There follows a list of these **System Ancillary Services**, together with the paragraph number of the **CC** (or other part of the **Grid Code**) in which the minimum capability is required or referred to. The list is divided into two categories: Part 1 lists the **System Ancillary Services** which **Generators** are obliged to provide, and Part 2 lists the **System Ancillary Services** which **Generators** will provide only if agreement to provide them is reached with **NGC**:

Part 1

(a) **Reactive Power** supplied under abnormal conditions otherwise than by means of synchronous or static compensators - BC2.5.4(c), or to be capable of operating at near zero hv Mvar - CC.6.3.4 ~~- CC.6.3.2~~

~~(b)~~ **Frequency** Control by means of **Frequency** sensitive generation - CC.6.3.7 and BC3.5.1

Part 2

(~~c~~b) **Frequency** Control by means of **Fast Start** - CC.6.3.14

(~~d~~c) **Black Start Capability** - CC.6.3.5

[3]Part 3

(d) **Reactive Power** supplied otherwise than by means of synchronous or static compensators to ensure that a satisfactory **System** voltage profile is maintained.

CC.8.2 **Commercial Ancillary Services**

Other **Ancillary Services** are also utilised by **NGC** in operating the **Total System** if these have been agreed to be provided by a **User** (or other person) under an **Ancillary Services Agreement** or under a **Supplemental Agreement**, with payment being dealt with under an **Ancillary Services Agreement** or in the case of **Externally Interconnected System Operators** or **Interconnector Users**, under any other agreement (and in the case of **Externally Interconnected System Operators** and **Interconnector Users** includes ancillary services equivalent to or similar to **System Ancillary Services**) ("**Commercial Ancillary Services**"). The capability for these **Commercial Ancillary Services** is set out in the relevant **Ancillary Services Agreement** or **Supplemental Agreement** (as the case may be). There follows a non-exhaustive list of these **Commercial Ancillary Services**. Where a **User** has agreed to provide any **Commercial Ancillary Services**, **NGC** will rely on those **Commercial Ancillary Services** when operating:

(a) **Frequency** Control by means of a **Pumped Storage Unit Spinning In Air**

(b) **Frequency** Control by means of **Demand** reduction

(c) **Reactive Power** supplied by means of synchronous or static compensators

(d) **Hot Standby**

In addition, there is also the **Ancillary Service** of **Cancelled Start**, which arises as part of the ordinary operational instruction of **Generating Units** and therefore needs no separate capability description.

## 4. Operating Code No 2 Extract

OC2.4.2.1 When a **Statement** of **Readiness** under the **Supplemental Agreement** is submitted, and thereafter in calendar week 24 in each calendar year,

(a) each **Generator** shall in respect of each of its:-

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[3] The allocation of reactive power services to particular types of Ancillary Service requires further consideration.

(i) **Gensets** (in the case of the **Generation Planning Parameters**); and

(ii) **CCGT Units** within each of its **CCGT Modules** at a **Large Power Station** (in the case of the **Generator Performance Chart**)

submit to **NGC** in writing the **Generation Planning Parameters** and the **Generator Performance Chart**.

(b) Each shall ~~meet the requirements of CC6.3.2 and shall~~ reasonably reflect the true operating characteristics of the **Genset**.

## 5. Operating Code No 5 Extract

OC5.5.1 **Reactive Power** Tests

OC5.5.1.1 **NGC** may at any time (although it may not do so more than twice in any calendar year in respect of any particular **Generating Unit** except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test) issue an instruction requiring a **Generator** to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the **Generator's Generating Units**, to demonstrate that the relevant **Generating Unit** meets the **Reactive Power** capability registered with **NGC** under **OC2**~~ which shall meet the requirements set out in CC.6.3.2~~. In the case of a test on a **Generating Unit** within a **CCGT Module** the instruction need not identify the particular **CCGT** Unit within the **CCGT Module** which is to be tested, but instead may specify that a test is to be carried out on one of the **CCGT Units** within the **CCGT Module**.

OC5.5.1.2 The instruction referred to in OC5.5.1.1 may only be issued if the relevant **Generator** has submitted **Export and Import Limits** which notify that the **Generating Unit** is available in respect of the **Operational Day** current at the time at which the instruction is issued, in which event the relevant **Generator** shall then be obliged to declare that **Generating Unit** available with **Export and Import Limits** with a magnitude greater than zero in respect of the time and the duration that the test is instructed to be carried out, unless that **Generating Unit** would not then be available by reason of forced outage or **Planned Outage** expected prior to this instruction. The **Export and Import Limits** in the case of a **CCGT Module** must include the same **CCGT Units** which were included in the **Export and Import Limits** in respect of the **Operational Day** current at the time at which the instruction is issued and must include, in relation to each of the **CCGT Units** within the **CCGT Module**, details of the various data in relation to each **CCGT Unit** in the form as set out in BC1.A.1.3 and BC1.A.1.5, which data **NGC** will utilise in instructing in accordance with this OC5 in issuing **Bid-Offer Acceptances**. The data shall reasonably reflect the true operating characteristics of each **CCGT Unit**.

OC5.5.1.3 The test will be initiated by the issue of instructions in the form specified in **BC2** (in accordance with the **Generating Unit's** data submitted under **BC1** prevailing on the **Operational Day** current at the time at which the instruction is issued) or in the case of a **CCGT Unit**, in accordance with the parameters submitted under OC5.5.1.2. The instructions in respect of a **CCGT Unit** within a **CCGT Module** will be in respect of the **CCGT Unit**, as provided in BC2.

OC5.5.1.4 The duration of the test will be for a period of up to 60 minutes during which period the **System** voltage at the **Grid Entry Point** for the relevant **Generating Unit** will be maintained by the **Generator** at the voltage specified pursuant to BC2.8 by adjustment of **Reactive Power** on the remaining **Generating Units**, if necessary.

OC5.5.1.5 The performance of the **Generating Unit** will be recorded on a chart recorder (with measurements taken on the **Generating Unit** Stator Terminals) in the relevant **Generator's Control Room**, in the presence of a reasonable number of representatives appointed and authorised by **NGC**, and the **Generating Unit** will pass the test if it is within ±5% of the capability registered with **NGC** under **OC2** ~~which shall meet the requirements set out in CC.6.3.2~~ (with due account being taken of any conditions on the **System** which may affect the results of the test). The relevant **Generator** must, if requested, demonstrate, to **NGC's** reasonable satisfaction, the reliability of the chart recorders, disclosing calibration records to the extent appropriate.

OC5.5.1.6 If the **Generating Unit** concerned fails to pass the test the **Generator** must provide **NGC** with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the **Generator** after due and careful enquiry. This must be provided within three **Business Days** of the test. If a dispute arises relating to the failure, **NGC** and the relevant **Generator** shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the **Generator** may by notice require **NGC** to carry out a re-test on 48 hours' notice which shall be carried out following the procedure set out in OC5.5.1.4 and OC5.5.1.5 and subject as provided in OC5.5.1.2, as if **NGC** had issued an instruction at the time of notice from the **Generator**.

OC5.5.1.7 If the **Generating Unit** concerned fails to pass the re-test and a dispute arises on that re-test, either party may use the **Disputes Resolution Procedure** for a ruling in relation to the dispute, which ruling shall be binding.

OC5.5.1.8 If following the procedure in OC5.5.1.6 and OC5.5.1.7 it is accepted that the **Generating Unit** has failed the test or re-test (as applicable), the **Generator** shall within 14 days, or such longer period as **NGC** may reasonably agree, following such failure, submit in writing to **NGC** for approval the date and time by which the **Generator** shall have brought the **Generating Unit** concerned to a condition where it complies with the **Reactive Power** capability registered with **NGC** under **OC2** ~~which shall meet the requirements set out in CC.6.3.2~~, and would pass the test. **NGC** will not unreasonably withhold or delay its approval of the **Generator's** proposed date and time submitted. Should **NGC** not approve the **Generator's** proposed date or time (or any revised proposal), the **Generator** should amend such proposal having regard to any comments **NGC** may have made and re-submit it for approval.

OC5.5.1.9 If a **Generating Unit** fails the test, the **Generator** may amend the relevant registered parameters of that **Generating Unit** relating to **Reactive Power** capability, registered in the **Generator Performance Chart** for that **Generating Unit** under **OC2**, for the period until the **Generating Unit** can achieve the parameters previously registered, as demonstrated in a re-test.

OC5.5.1.10 Once the **Generator** has indicated to **NGC** the date and time that the **Generating Unit** can achieve the parameters previously registered, **NGC** shall either accept this information or require the **Generator** to demonstrate that the **Reactive Power** capability at the **Generating Unit** concerned has been restored so that it meets the **Reactive Power** capability registered with **NGC** under **OC2**~~ which shall meet the requirements set out in CC.6.3.2~~, by means of a repetition of the test referred to in OC5.5.1.1 by an instruction requiring the **Generator** on 48 hours notice to carry out such a test. The provisions of this OC5.5.1 will apply to such further test.

OC5.5.1.11 Testing of synchronous compensation will also be carried out under the procedure set out in this OC5.5.1.

## 6. Balancing Code No 2 Extracts

### BC2.5.4 <u>Operation in the absence of instructions from **NGC**</u>

In the absence of any **Bid-Offer Acceptances**, **Ancillary Service** instructions issued pursuant to BC2.8 or **Emergency Instructions** issued pursuant to BC2.9:

(a) as provided for in BC3, each **Synchronised Genset** producing **Active Power** must operate at all times in **Limited Frequency Sensitive Mode** (unless instructed in accordance with BC3.5.4 to operate in **Frequency Sensitive Mode**);

(b) in the absence of any MVAr **Ancillary Service** instructions, the MVAr output of each **Synchronised Genset** should be 0 MVAr upon **Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**;

(c) the excitation system, unless otherwise agreed with **NGC**, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service, with any constant **Reactive Power** output control mode or constant **Power Factor** output control mode always disabled, unless agreed otherwise with **NGC**. In the event of any change in **System** voltage, a **Generator** must not take any action to override automatic MVAr response which is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by **NGC** or unless immediate action is necessary to comply with **Stability Limits** or unless constrained by plant operational limits or safety grounds (relating to personnel or plant);

(d) In the absence of any MVAr **Ancillary Service** instructions, the MVAr output of each **Genset** should be 0MVAr immediately prior to **De-Synchronisation** at the circuit-breaker where the **Genset** is **Synchronised**, other than in the case of a rapid unplanned **De-Synchronisation**.

……………………………………….

BC2.7.5 Additional Action Required from **Generators**

(a) When complying with **Bid-Offer Acceptances** for a **CCGT Module** a **Generator** will operate its **CCGT Units** in accordance with the applicable **CCGT Module Matrix**.

(b) When complying with **Bid-Offer Acceptances** for a **CCGT Module** which is a **Range CCGT Module**, a **Generator** must operate that **CCGT Module** so that power is provided at the single **Grid Entry Point** identified in the data given pursuant to PC.A.3.2.1 or at the single **Grid Entry Point** to which **NGC** has agreed pursuant to BC1.4.2 (f).

(c) On receiving a new MW **Bid-Offer Acceptance**, no tap changing shall be carried out to change the MVAr output unless there is a new MVAr **Ancillary Service** instruction issued pursuant to BC2.8.

**……………………..**

BC2.A.2.1 This part of the Appendix consists of a non-exhaustive list of the forms and types of instruction for a **Genset** to provide **System Ancillary Services.** There may be other types of **Commercial Ancillary Services** and these will be covered in the relevant **Ancillary Services Agreement**.

[4]As described in CC.8, **System Ancillary Services** consist of Part 1, Part 2 and Part ~~2~~3 **System Ancillary Services.**

Part 1 System Ancillary Services comprise:

(a) **Reactive Power** supplied other than by means of synchronous or static compensators~~. This is required to ensure that a satisfactory **System** voltage profile is maintained and that sufficient **Reactive Power** reserves are maintained~~ under ~~normal and fault~~ abnormal conditions. **Ancillary Service** instructions in relation to **Reactive Power** may include:

~~(i) MVAr Output~~ Tap change to return to near zero hv Mvar output
~~(ii) Target Voltage Levels~~
~~(iii) Tap Changes~~
(iv) Maximum MVAr Output (‘maximum excitation’)
(v) Maximum MVAr Absorption (‘minimum excitation’)

[4] As indicated elsewhere, the allocation of reactive power provision to particular types of Ancillary Services is to be the subject of further consideration.

(b) **Frequency** Control by means **of Frequency** sensitive generation. **Gensets** may be required to move to or from **Frequency Sensitive Mode** in the combinations agreed in the relevant **Ancillary Services Agreement**. They will be specifically requested to operate so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response**.

Part 2 System Ancillary Services comprise:

(a) **Frequency** Control by means of **Fast Start.**

(b) **Black Start Capability**

Part 3 System Ancillary Services comprise:

(a) **Reactive Power** supplied other than by means of synchronous or static compensators under normal conditions. This is required to ensure that a satisfactory **System** voltage profile is maintained and that sufficient **Reactive Power** reserves are maintained under normal conditions. **Ancillary Service** instructions in relation to **Reactive Power** may include:

(i) MVAr Output
(ii) Target Voltage Levels
(iii) Tap Changes

BC2.A.2.2 As **Ancillary Service** instructions are not part of **Bid-Offer Acceptances** they do not need to be closed instructions and can cover any period of time, not just limited to the period of the **Balancing Mechanism**.

BC2.A.2.3 As described in BC2.6.1 **Ancillary Service** instructions are normally given by automatic logging device, but in the absence of, or in the event of failure of the logging device, instructions will be given by telephone.

BC2.A.2.4 INSTRUCTIONS GIVEN BY AUTOMATIC LOGGING DEVICE.

(a) The complete form of the **Ancillary Service** instruction is given in the EDL Message Interface Specification which is available to **Users** on request from **NGC**.

(b) **Ancillary Service** instructions for **Frequency** Control will normally follow the form:

(i) **BM Unit** Name
(ii) Instruction Reference Number
(iii) Time of instruction
(iv) Type of instruction (REAS)
(v) Reason Code
(vi) Start Time

(c) **Ancillary Service** instructions for **Reactive Power** will normally follow the form:

(i) **BM Unit** Name
(ii) Instruction Reference Number
(iii) Time of instruction
(iv) Type of instruction (MVAR, VOLT or TAPP)

(v) Target Value
(vi) Target Time

The times required in the instruction are input and displayed in London time, but communicated electronically in GMT.

BC2.A.2.5 INSTRUCTIONS GIVEN BY TELEPHONE

(a) **Ancillary Service** instructions for **Frequency** Control will normally follow the form:

(i) an exchange of operator names;
(ii) **BM Unit** Name;
(iii) Time of instruction;
(iv) Type of instruction;
(v) Start Time.

The times required in the instruction are expressed in London time.

For example, for **BM Unit** ABCD-1 instructed at 1400 hours to provide Primary and **High Frequency** response starting at 1415 hours:

"**BM Unit** ABCD-1 message timed at 1400 hours. Unit to **Primary and High Frequency Response** at 1415 hours"

(b) **Ancillary Service** instructions for **Reactive Power** will normally follow the form:

(i) an exchange of operator names;
(ii) **BM Unit** Name;
(iii) Time of instruction;
(iv) Type of instruction (MVAR, VOLT or TAPP)
(v) Target Value
(vi) Target Time.

The times required in the instruction are expressed as London time.

For example, for **BM Unit** ABCD-1 instructed at 1400 hours to provide 100MVAr by 1415 hours:

"**BM Unit** ABCD-1 message timed at 1400 hours. MVAR instruction. Unit to plus 100 MVAr target time 1415 hours."

BC2.A.2.6 **Reactive Power**

As described in BC2.A.2.4 and BC2.A.2.5 instructions for **Ancillary Services** relating to **Reactive Power** may consist of any of several specific types of instruction. The following table describes these instructions in more detail:

| Instruction Name | Description | Type of Instruction |
|---|---|---|
| MVAr Output | The individual MVAr output from the **Genset** onto the **NGC Transmission System** at the **Grid Entry Point** (or onto the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**), namely on the higher voltage side of the generator step-up transformer. In relation to each **Genset**, where there is no HV indication, **NGC** and the **Generator** will discuss and agree equivalent MVAr levels for the corresponding LV indication.<br><br>Where a **Genset** is instructed to a specific MVAr output, the **Generator** must achieve that output within a tolerance of ±25 MVAr (or such other figure as may be agreed with **NGC**) by tap changing on the generator step-up transformer, unless agreed otherwise. Once this has been achieved, the **Generator** will not tap again without prior consultation with and the agreement of **NGC**, on the basis that MVAr output will be allowed to vary with **System** conditions. | MVAR |
| Target Voltage Levels | Target voltage levels to be achieved by the **Genset** on the **NGC Transmission System** at the **Grid Entry Point** (or on the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**, namely on the higher voltage side of the generator step-up transformer. Where a **Genset** is instructed to a specific target voltage, the **Generator** must achieve that target within a tolerance of ±1 kV (or such other figure as may be agreed with **NGC**) by tap changing on the generator step-up transformer, unless agreed otherwise with **NGC**. In relation to each **Genset**, where there is no HV indication, **NGC** and the **Generator** will discuss and agree equivalent voltage levels for the corresponding LV indication.<br><br>Under normal operating conditions, once this target voltage level has been achieved the **Generator** will not tap again without prior consultation with, and with the agreement of, **NGC**.<br><br>However, under certain circumstances the **Generator** may be instructed to maintain a target voltage until otherwise instructed and this will be achieved by tap changing on the generator step-up transformer without reference to **NGC**. | VOLT |
| Tap Changes | Details of the required generator step-up transformer tap changes in relation to a **Genset**. The instruction for tap changes may be a **Simultaneous Tap Change** instruction, whereby the tap change must be effected by the **Generator** in response to an instruction from **NGC** issued simultaneously to relevant **Power Stations**. The instruction, which is normally preceded by advance notice, must be effected as soon as possible, and in any event within one minute of receipt from **NGC** of the instruction.<br><br>For a **Simultaneous Tap Change,** change **Genset** generator step-up transformer tap position by one [two] taps to raise or lower (as relevant) **System** voltage, to be executed at time of instruction. | TAPP |

| Instruction Name | Description | Type of Instruction |
|---|---|---|
| Maximum MVAR Output (“maximum excitation”) | Under certain conditions, such as low **System** voltage, an instruction to maximum MVAr output at instructed MW output ("maximum excitation") may be given, and a **Generator** should take appropriate actions to maximise MVAr output unless constrained by plant operational limits or safety grounds (relating to personnel or plant). | |
| Maximum MVAr Absorption ("minimum excitation") | Under certain conditions, such as high **System** voltage, an instruction to maximum MVAr absorption at instructed MW output ("minimum excitation") may be given, and a **Generator** should take appropriate actions to maximise MVAr absorption unless constrained by plant operational limits or safety grounds (relating to personnel or plant). | |

BC2.A.2.7 In addition, the following provisions will apply to **Reactive Power** instructions:

(a) In circumstances where **NGC** issues new instructions in relation to more than one **BM Unit** at the same **Power Station** at the same time tapping will be carried out by the **Generator** one tap at a time either alternately between (or in sequential order, if more than two), or at the same time on, each **BM Unit**.

(b) Where the instructions require more than two taps per **BM Unit** and that means that the instructions cannot be achieved within 2 minutes of the instruction time (or such longer period at **NGC** may have instructed), the instructions must each be achieved with the minimum of delay after the expiry of that period.

(c) It should be noted that should **System** conditions require, **NGC** may need to instruct maximum MVAr output to be achieved as soon as possible, but (subject to the provisions of paragraph (BC2.A.2.7(b) above) in any event no later than 2 minutes after the instruction is issued.

(d) An **Ancillary Service** instruction relating to **Reactive Power** may be given in respect of **CCGT Units** within a **CCGT Module** at a **Power Station** where running arrangements and/or **System** conditions require, in both cases where exceptional circumstances apply and connection arrangements permit.

(e) In relation to MVAr matters, MVAr generation/output is an export onto the **System** and is referred to as "lagging MVAr", and MVAr absorption is an import from the **System** and is referred to as "leading MVAr".

(f) It should be noted that the excitation control system constant **Reactive Power** output control mode or constant power factor output control mode will always be disabled, unless agreed otherwise with **NGC**.

## Appendix 3 – Submission of Revised MVAr Capability

BC2.A.3.1 For the purpose of submitting revised MVAr data the following terms shall apply:

Full Output — The MW output of a **Generating Unit** measured at the generator stator terminals representing the LV equivalent of the **Registered Capacity** at the **Grid Entry Point**.

Minimum Output — The MW output of a **Generating Unit** measured at the generator stator terminals representing the LV equivalent of the **Minimum Generation** at the **Grid Entry Point**.

BC2.A.3.2 The following provisions apply to faxed submission of revised MVAr data:

(a) The fax must be transmitted to **NGC** (to the relevant location in accordance with GC6) and must contain all the sections from the relevant parts of Annexures ~~A~~1, 2 and 3 but with only the data changes set out. The "notification time" must be completed to refer to the time of transmission, where the time is expressed as London time.

(b) Upon receipt of the fax, **NGC** will acknowledge receipt by sending a fax back to the **User**. The acknowledgement will either state that the fax has been received and is legible or will state that it (or part of it) is not legible and will request re-transmission of the whole (or part) of the fax.

(c) Upon receipt of the acknowledging fax the **User** will, if requested, re-transmit the whole or the relevant part of the fax.

(d) The provisions of paragraphs (b) and (c) then apply to that re-transmitted fax.

BC2.A.3.3 Annexure 1 comprises a Fax header sheet which should be sent in all cases, accompanied by a copy of Annexure 2 and/or Annexure 3. Annexure 2 comprises a form for notifying changes to the operational **capability** of the **Generating Unit**. Annexure 3 comprises a form for notifying the capability that is being made available for the purposes of **Ancillary Services**.

**Optional Logo**

# *Company name* **REVISED MVAr DATA**

TO: NGC National Grid Control Centre Fax telephone No.

Number of pages inc. header:.............................

Sent By : ..........................................................................................................

Return Acknowledgement Fax to ...................................................................

For Retransmission or Clarification ring.........................................................

---

Acknowledged by NGC: (Signature) .....................................................................

Acknowledgement time and date .........................................................................

| | | | |
|---|---|---|---|
| Legibility of FAX : | Acceptable | ☐ | |
| Unacceptable<br>(List pages if appropriate) | | ☐ | ( Resend FAX ) |

APPENDIX 3 - ANNEXURE 2

To: NGC National Grid Control Centre

From : [*Company Name & Location* ]

**REVISED TECHNICAL MVAr DATA**

NOTIFICATION TIME:

| HRS MINS DD MM YY |
|---|
| . / / |

| GENERATING UNIT* | |
|---|---|

Start Time/Date (if not effective immediately)

**REACTIVE POWER CAPABILITY AT GENERATOR STATOR TERMINAL** (at rated terminal volts)

| | MW | LEAD (MVAr) | LAG (MVAr) |
|---|---|---|---|
| AT **RATED MW** | | | |
| AT FULL OUTPUT (MW) | | | |
| AT MINIMUM OUTPUT (MW) | | | |

**GENERATING UNIT STEP-UP TRANSFORMER DATA**

| TAP CHANGE RANGE (+%,-%) | TAP NUMBER RANGE |
|---|---|
| | |

~~**OPTIONAL INFORMATION** (for Ancillary Services use only) -~~
~~**REACTIVE POWER CAPABILITY AT COMMERCIAL BOUNDARY** (at rated stator terminal and nominal system volts)~~

| | ~~LEAD (MVAr)~~ | ~~LAG (MVAr)~~ |
|---|---|---|
| ~~AT **RATED MW**~~ | | |

Predicted End Time/Date (to be confirmed by redeclaration)

Redeclaration made by (Signature) ____________________________________

* For a CCGT, the redeclaration is for an individual CCGT unit and not the entire module.

APPENDIX 3 - ANNEXURE 3

To: NGC National Grid Control Centre

From : [*Company Name & Location* ]

**REVISED COMMERCIAL MVAr DATA**

NOTIFICATION TIME:

| HRS MINS DD MM YY |
|---|
| . / / |

| GENERATING UNIT or CCGT MODULE | |
|---|---|

Start Time/Date (if not effective immediately)

(for Ancillary Services use only) **-**
**REACTIVE POWER CAPABILITY AT COMMERCIAL BOUNDARY** (at rated stator terminal and nominal system volts)

| | LEAD (MVAr) | LAG (MVAr) |
|---|---|---|
| AT **RATED MW** | | |

Predicted End Time/Date (to be confirmed by redeclaration)

Redeclaration made by (Signature) ____________________________________________

# 7. Data Registration Code Extract

SCHEDULE 1
Page 3 of 10

| DATA DESCRIPTION | UNITS | DATA CAT. | GENERATING UNIT (OR CCGT MODULE, AS THE CASE MAY BE) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | G1 | G2 | G3 | G4 | G5 | G6 | STN |
| Expected running regime (eg. 7d 3s = 7 day 3 shift) | | | | | | | | | |
| Rated MVA | MVA | **SPD+** | | | | | | | |
| Rated MW | MW | **SPD+** | | | | | | | |
| **Rated Power Factor** | | **SPD+** | | | | | | | |
| Rated terminal voltage | kV | **DPD** | | | | | | | |
| *Performance Chart at **Generating Unit** stator terminals | | **SPD** | (see **OC2** for specification) | | | | | | |
| ***Output Usable** (on a monthly basis) | MW | **SPD** | (except in relation to **CCGT Modules** when required on a unit basis under the **Grid Code,** this data item may be supplied under Schedule 3) | | | | | | |
| Turbo-Generator inertia constant (for synchronous machines) | MW secs /MVA | **SPD+** | | | | | | | |
| Short circuit ratio (synchronous machines) | | **SPD+** | | | | | | | |
| Normal auxiliary load supplied by the **Generating Unit** at rated MW output | MW<br>MVAr | **DPD**<br>**DPD** | | | | | | | |
| Rated field current at rated MW and MVAr output and at rated terminal voltage | A | **DPD** | | | | | | | |
| Field current open circuit saturation curve (as derived from appropriate manufacturers' test certificates): | | | | | | | | | |
| 120% rated terminal volts | A | **DPD** | | | | | | | |
| 110% rated terminal volts | A | **DPD** | | | | | | | |
| 100% rated terminal volts | A | **DPD** | | | | | | | |
| 90% rated terminal volts | A | **DPD** | | | | | | | |
| 80% rated terminal volts | A | **DPD** | | | | | | | |
| 70% rated terminal volts | A | **DPD** | | | | | | | |
| 60% rated terminal volts | A | **DPD** | | | | | | | |
| 50% rated terminal volts | A | **DPD** | | | | | | | |
| IMPEDANCES:<br>(Unsaturated) | | | | | | | | | |
| Direct axis synchronous reactance | % on MVA | **DPD** | | | | | | | |
| Direct axis transient reactance | % on MVA | **SPD+** | | | | | | | |
| Direct axis sub-transient reactance | % on MVA | **DPD** | | | | | | | |
| Quad axis synch reactance | % on MVA | **DPD** | | | | | | | |
| Quad axis sub-transient reactance | % on MVA | **DPD** | | | | | | | |
| Stator leakage reactance | % on MVA | **DPD** | | | | | | | |
| Armature winding direct current resistance. | % on MVA | **DPD** | | | | | | | |

Note:- the above data item relating to armature winding direct-current resistance need only be provided by **Generators** in relation to **Generating Units** commissioned after 1st March 1996 and in cases where, for whatever reason, the **Generator** is aware of the value of the data item.

End of report