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CONSULTATION DOCUMENT

GB SQSS Review Request GSR007

Review of Infeed Loss Limits

**Prepared by the Infeed Loss Working Group
for submission to the GB SQSS Review Group**

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1 EXECUTIVE SUMMARY

1.1 Background

The Government believes that there is a greater need to use more renewable energy, given the urgency of tackling climate change and the need to maintain secure domestic energy supplies. The European Union has recently agreed that by 2020 one-fifth of all Europe's energy should come from renewable sources. In line with this agreement, the European Commission has proposed a target whereby 15% of UK energy will be supplied by renewable sources. Achieving this target could require renewable generators to provide between 30% and 40% of our electricity supplies. Over the same period, a significant portion of our existing conventional and nuclear generation capacity will need to be replaced with new lower carbon generation.

However, it is also recognised that renewable generation does not represent the only means of reducing greenhouse gas emissions. Substantial decarbonisation of future power generation can be achieved by an appropriate mix of renewables, by coal fired generation with carbon capture and storage and, not least, by new nuclear generation. The Government has stated on a number of occasions over the years 2007 and 2008 that it believes it desirable that the GB generation market develops to deliver a fleet of new nuclear units within the next ten years. At least one new nuclear technology under consideration involves units in excess of 1320MW.

It may be argued that the current GB SQSS acts as a barrier, not only to the timely access to the GB transmission system of the high volumes of renewable generation, but also to the timely access of the large generating units (i.e. in excess of 1320MW) currently being considered. These include nuclear units which could pose a loss of power infeed risk of up to 1800MW and coal fired plants of unit sizes greater than 1000MW.

The current GB SQSS planning criteria were not designed for the connection of such large single units. The advent of such large generating units presents new challenges both in operational and planning timescales. The GB SQSS, and the GB transmission system, needs to continually evolve to ensure the continued development and operation of an economic and efficient transmission system and to facilitate continued competition in the electricity market.

GB SQSS Review Request GSR007 was raised by EDF Energy in February 2008, to review the normal and infrequent loss limits in the GB SQSS. Currently, the GB SQSS requires that the GB transmission system is planned on the basis of accepting a normal (i.e. relatively frequent) loss of power infeed of up to 1000MW and an infrequent (i.e. in the region of up to four occurrences per year) loss of power infeed of up to 1320MW. The GB SQSS requires that the GB transmission system is operated such that, under prevailing system conditions and for the secured event of the 'most onerous loss of power infeed' occurring, unacceptable frequency conditions shall not arise.

These 1000MW and 1320MW threshold limits to the normal and infrequent power infeed loss would become inappropriate in the event of new single units of capacity in excess of 1320MW being connected to the system. The connection of such large capacity units is currently being considered by several parties.

This report considers the implications of raising the threshold levels of the normal and infrequent infeed loss risk limits. Issues considered include: transmission planning; operation; and cost including the cost associated with the GB System Operator (GBSO) needing to hold additional response and reserve to contain frequency deviations to within statutory limits; and the implementation date for any change.

1.2 Working Group Recommendations

The recommendations of the Working Group are that:

- The threshold level for the 'Normal Infeed Loss Risk' shall be retained at its current level of 1000MW until the 'infeed change date' (see below) thereafter the level should be increased to 1320MW;
- The threshold level for the 'Infrequent Infeed Loss Risk' shall be retained at its current level of 1320MW until the 'infeed change date' (see below) thereafter the level should be increased to 1800MW;
- The 'Infeed Change Date' shall be the date on which a single generating unit, CCGT Module, boiler or nuclear reactor of Registered Capacity greater than 1320MW connects to the GB transmission system and commissions; and
- Paragraph 2.6.3 of the current GB SQSS shall be modified to refer to the 'infrequent infeed loss risk' rather than the 'normal infeed loss risk'.

Amongst other things, implementation of these changes will:

- Facilitate the connection of the single generating units, and groups of generating units, with capacities in excess of 1320MW (posing a loss of power infeed risk of up to 1800MW);
- In general, reduce the number of circuit breakers required in substation design;
- Support the use of larger cable sizes in the design of offshore transmission systems;
- Facilitate the connection of larger External Interconnections;
- Require additional primary and secondary response holding;

However, the Working Group notes that, in the event that the number of large units increases to a level where a loss of power infeed of up to 1800MW may be regarded as having a frequency of occurrence that may not reasonably be regarded as 'infrequent', then the GB SQSS should be subject to further review.

The Working Group believes that: the work outlined in the Working Group Terms of Reference has now been completed; the Review Request GSR007 has been fully considered; and recommends to the GB SQSS Review Group that this Consultation Document should proceed to wider industry consultation in early February 2009.

2 INTRODUCTION

The Government believes that there is a greater need to use more renewable energy, given the urgency of tackling climate change and the need to maintain secure domestic energy supplies. The European Union has recently agreed that by 2020 one-fifth of all Europe's energy should come from renewable sources. In line with this agreement, the European Commission has proposed a target whereby 15% of UK energy will be supplied by renewable sources. Achieving this target could require renewable generators to provide between 30% and 40% of our electricity supplies. Over the same period, a significant portion of our existing conventional and nuclear generation capacity will need to be replaced with new lower carbon generation.

However, it is also recognised that renewable generation does not represent the only means of reducing greenhouse gas emissions. Substantial decarbonisation of future power generation can be achieved by an appropriate mix of renewables, by coal fired generation with carbon capture and storage and, not least, by new nuclear generation. The Government has stated on a number of occasions over the years 2007 and 2008 that it believes it desirable that the GB generation market develops to deliver a fleet of new nuclear units within the next ten years. At least one new nuclear technology under consideration involves units in excess of 1320MW.

It may be argued that the current GB SQSS acts as a barrier, not only to the timely access to the GB transmission system of the high volumes of renewable generation, but also to the timely access of the large generating units (i.e. in excess of 1320MW) currently being considered. These include nuclear units which could pose a loss of power infeed risk of up to 1800MW and coal fired plants of unit sizes greater than 1000MW.

The current GB SQSS planning criteria were not designed for the connection of such large single units. The advent of such large generating units presents new challenges both in operational and planning timescales. The GB SQSS, and the GB transmission system, needs to continually evolve to ensure the continued development and operation of an economic and efficient transmission system and to facilitate continued competition in the electricity market.

The GB SQSS Review Request (GSR007), 'Review of Infeed Loss Limits' was proposed by EDF Energy in February 2008. The GB SQSS Review Group determined on 10th April 2008 that the proposal should be considered by a Working Group, who would report back to the Review Group by April 2009.

The Working Group has met on some six occasions over the period June to December 2008. The Terms of Reference for the Working Group, which are presented as Annex 2 to this report, were accepted by Working Group members at their meeting on 3rd July 2008. The Working Group will report to the Review Group in January 2009, and expects to be able to report that the work outlined in the Terms of Reference is now complete.

This Consultation Document has been prepared in accordance with the governance principles of the GB SQSS. An electronic copy of the governance principles and the GB SQSS Review Request Form for GSR007 may be accessed from the National Grid Website at:

<https://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/reviews/>

3 OVERVIEW OF CURRENT POSITION

3.1 Statutory Frequency Requirements

The Electricity Safety, Quality and Continuity (Amendment) Regulations 2006, Part IV, clause 27 (commonly referred to as the ESQCR) requires that system frequency shall not vary more than one percent above or below the declared frequency of 50Hz save in 'exceptional circumstances'.

For many years the former CEGB took the phrase 'exceptional circumstances' to mean that the system frequency shall not transgress outside the statutory limits of 50Hz +/- 0.5Hz (i.e. 50.5Hz to 49.5Hz) more than four times a year. Whilst National Grid has continued to use the CEGB interpretation, there is no absolute mandate to maintain this precise number of transgressions as a limit. Nevertheless, it is considered reasonable to use this frequency of occurrence as a general indicator as to what may be considered frequent and what may be considered infrequent.

The current GB SQSS definition of "unacceptable frequency conditions" is:

These are conditions where:

- i) the steady state frequency falls outside the statutory limits of 49.5Hz to 50.5Hz; or*
- ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5Hz to 50.5Hz within 60 seconds.*

Transient frequency deviations outside the limits of 49.5Hz and 50.5Hz shall only occur at intervals which ought reasonably be considered as infrequent. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which NGC shall adjust from time to time to meet the security and quality requirements of this Standard.

3.1.1 NGET's Frequency Containment Policy

The statutory requirements relating to system frequency are included in NGET's frequency containment policy. The frequency containment policy is such that:

- a) For a 'significant loss' of generation or demand up to 1000MW, the maximum change of frequency shall not be greater than +/- 0.5Hz;
- b) For an 'abnormal loss' of generation up to 1320MW, the maximum change of frequency shall not be greater than -0.8Hz;
- c) If the system frequency is 49.8Hz (i.e. the lower operational limit) prior to an 'abnormal loss' of 1320MW, then the frequency shall not fall below 49Hz. This is to maintain a margin of 0.2Hz above the first stage of emergency low frequency demand disconnection at 48.8Hz;
- d) Any frequency deviation outside the 50.5Hz to 49.5Hz shall not exceed one minute.

The frequency containment policy equates a 'significant loss' (under normal circumstances) with the normal infeed loss risk of 1000MW and an 'abnormal

loss' (under exceptional circumstances) with the infrequent infeed loss risk of 1320MW.

The current values of 1000MW and 1320MW are also a function of NGET's obligations to contain costs. An increase in either of these values or their frequency of occurrence would lead to the need for more frequency response and reserve holding and incur higher operational cost although, it may be argued, reduced investment in some circumstances.

3.2 GB SQSS Planning and Operational Criteria

The transmission licensees are required to plan, operate and maintain the transmission system in an efficient and economical manner and to facilitate competition in the electricity market. Compliance with the GB SQSS is an electricity transmission licence requirement. Standard condition C17 obliges National Grid (NGET) to plan and develop its transmission system and to operate the GB transmission system in accordance with the GB SQSS. Standard condition D3 obliges SP Transmission (SPT) and Scottish Hydro Electric Transmission (SHETL) to plan and develop their transmission systems in accordance with the GB SQSS.

The planning and operational criteria of the GB SQSS are set out in the form of specified secured events for which specified unacceptable conditions shall not arise. Naturally, unforeseen events beyond the secured events set out in the GB SQSS can occur. Such events would also fall within the category of 'exceptional circumstances' and, for these, system frequency may deviate beyond the limits described in the ESQCR. Nevertheless, such deviations would indeed be 'exceptional' and are therefore permitted under the ESQCR.

3.2.1 Planning Criteria

An aim of the planning criteria is to ensure that sufficient transmission investment and/or capability for purchase of services (e.g. reactive power) is provided in planning timescales to enable secure and efficient real time operation in accordance with the operational criteria.

In relation to system frequency, the planning criteria are concerned with designing the system such that, consistent with the frequency containment policy, a loss of power infeed of up to 1000MW is considered as a 'normal' event and a loss of power infeed of up to 1320MW is considered an 'infrequent' event. The actual containment of frequency to within required limits is the subject of the GB SQSS operational criteria and the frequency containment policy.

The criteria relating to the design of generation connections include those concerning 'Limits to the Loss of Power Infeed (LOPI) Risk'. Application of these criteria determines the minimum number of circuits, busbars and switchgear required.

For example, the LOPI criteria require that generation connections shall be planned such that, starting with an intact system, following the secured event of a planned outage of any single section of busbar there shall be no loss of power infeed. Following the fault outage of a single section of busbar (a 'normal' occurrence) the loss of power infeed shall not exceed the normal infeed loss risk (i.e. 1000MW). Following the secured event of any single busbar coupler or section circuit breaker (an 'infrequent' occurrence), the loss of power infeed shall not exceed the infrequent infeed loss risk (i.e.

1320MW). Elsewhere in this report, such a risk posed by the connection of generating units is sometimes loosely referred to as a 'generation risk' for convenience.

As a further example, the LOPI criteria also require that generation connections shall be planned such that, starting with an intact system, following the secured event of any two transmission circuits on the same double circuit overhead line, or a single transmission circuit during the planned outage of any other single transmission circuit, the loss of power infeed shall not exceed the infrequent infeed loss risk (i.e. 1320MW). Elsewhere in this report, such a risk posed by transmission circuits is sometimes loosely referred to as a 'transmission risk' for convenience.

3.2.2 Variations to Connection Designs

It is permissible to design to standards higher than those set out in the planning criteria for the design of generation connections provided that the higher standard can be economically justified (e.g. clause 2.4 of the GB SQSS refers).

In addition, a customer (e.g. generator) may choose a lower standard of connection provided that the conditions of the 'variations to connection designs' clause are met (clause 2.15 of the GB SQSS refers). Those conditions include the requirement that the varied design must not compromise any GB transmission licensee's ability to meet other statutory or licence obligations.

For example, the generator may wish to connect more than 1320MW across a single busbar section circuit breaker. Since this would have implications relating to the level of security provided to all customers (e.g. in relation to LOPI and frequency containment) mitigating measures would need to be put in place and paid for by the customer. The cost of such measures (e.g. holding additional response and reserve) would be balanced against the cost of transmission investments required to fully meet the criteria (e.g. additional busbar sections and switches).

3.2.3 Operational Criteria

The operational criteria together with the frequency containment policy are used to ensure that frequency remains within acceptable limits given the investment and/or purchase of services provided in planning timescales.

The operational criteria of the GB SQSS deliberately do not refer to either normal or infrequent infeed loss risk. Given the system as designed in planning timescales, the operational criteria require that, under prevailing system conditions and for the secured event of the 'most onerous loss of power infeed' occurring, unacceptable frequency conditions shall not arise. Sufficient frequency reserve and response is held in operational timescales to contain the system frequency to within statutory limits to mitigate effects of the most onerous loss of power infeed. Where there is a perceived risk of an infrequent event, which could lead to frequency deviation outside the statutory limit of 49.5Hz, sufficient reserve is held in operational timescales to contain such frequency deviations to within 49.0Hz and to limit their duration outside the 49.5Hz limit to 60 seconds.

3.3 Drivers for Change

The 1000MW and 1320MW thresholds would need reviewing should the power system evolve such that there was, for instance:

- A loss of power infeed risk greater than 1320MW (e.g. due to the introduction of a single generating unit with a capacity greater than 1320MW). For one off instances where a generator wishes to connect a generating unit, or units, totalling greater than 1000MW to a single busbar or more than 1320MW across a switch, that generator may use the variation to design clause and pay for additional reserve to ensure the quality of supply to other users is not reduced.

However, where technology has developed such that there is a reasonable likelihood that single units greater than 1320MW will become relatively commonplace in the future, then there is a clear case for increasing the threshold to avoid discrimination against such large units; or

- An increased frequency of occurrence of a loss of power infeed of 1320MW such that it could no longer be reasonably considered 'infrequent' or 'exceptional' (e.g. due to the introduction of external interconnections importing 1320MW subject to interruption materially more than in the region of up to four times per year).

The current definitions of the two terms (i.e. normal and infrequent infeed loss risk) leave scope for reviewing the thresholds should the need arise in the event of either of these developments. For clarity, the current GB SQSS definitions of normal and infrequent infeed loss risk are repeated below:

Infrequent Infeed Loss Risk:

That level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5Hz to 50.5Hz for more than 60 seconds. Until reviewed this is 1320MW.

Normal Infeed Loss Risk:

That level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5Hz. Until reviewed this is 1000MW.

It may be noted that the above current definitions provide inbuilt scope for changing the threshold levels of normal and infrequent loss risk to take account of technological and other developments.

4 REVIEW REQUEST

A copy of EDF Energy's GB SQSS Review Request Form (GSR007), titled 'Review of Infeed Loss Limits' is presented as Annex 1 to this report. The main motivation behind the review is the proposal to develop new nuclear power station designs for connection to the GB transmission system. Three designs were submitted for 'Generic Design Assessment (GDA)' in July 2008. These designs have export capabilities of some 1150MW, 1600MW and 1650MW,

which would impose maximum infeed loss risks on the transmission system of some 1250MW 1750MW and 1800MW respectively¹.

Maximum risks of this size are well outside the current levels of the normal and infrequent infeed loss risk under the GB SQSS, which are set at 1000MW and 1320MW respectively. The Review Request proposes a wide-scale review of all impacts of changing the thresholds levels for normal and infrequent infeed loss risk under the GB SQSS, and this is addressed within this report. The Review Request is not limited to nuclear technologies, and observes that coal-fired plants of unit sizes greater than 1000MW are under development in Europe.

5 GB SQSS PLANNING AND OPERATIONAL IMPLICATIONS

The potential planning and operational implications of increasing the current normal and infrequent infeed loss risk thresholds such that they are reflective of the physical capacities of the next generation of power station contracted to connect to the GB transmission system in the next ten years are summarised below:

5.1 Planning Implications

- There is a clear potential for generating units, larger than previously experienced, to be connected to the GB transmission system in the future. Two of the three nuclear designs, submitted for Generic Design Assessment in July 2008, involve units with capacities in excess of 1320MW². In addition super-critical coal fired units, with capacities in excess of 1000MW, are also under consideration across Europe.
- Generation groups with a total capacity in excess of 1320MW could connect to the GB transmission system on one double-circuit spur.
- In general, fewer circuit breakers would be required in substation design. For example, three 500MW generators could be connected to a single section of busbar. Currently, such a design is not permitted as a busbar section fault would cause a loss of power infeed in excess of the current normal infeed loss limit (1000MW).
- Larger cables sizes could be used in the design of offshore connections. At present, it has been determined that the development of the GB SQSS to include offshore transmission systems should be subject to the same limitation on loss of power infeed as onshore (i.e. a normal and infrequent loss risk of 1000MW and 1320MW respectively). Accordingly, should the thresholds be increased the maximum loss of power infeed risk from a single cable connection may also exceed 1320MW.
- External interconnections between the GB transmission system and external systems (e.g. France or Norway) are covered by separate agreements which will normally be consistent with the GB SQSS. The GB SQSS may be specifically referenced in the relevant agreements and apply

¹ Unit and/or power station demand is normally supplied by the nuclear power station. In the event of a power station trip, the unit and/or power station demand is switched to supply from the GB transmission system. Accordingly, the net loss of power infeed risk is equal to the power station export capability plus the unit and/or power station demand.

² The GE Hitachi ESBWR has subsequently been temporarily suspended from this process.

to the extent of that reference. However, their connection to the GB transmission system is subject to the requirements of the GB SQSS.

With regard to imports across external interconnections from external systems, the loss of power infeed risk posed by the larger single-risk components, such as cables or bipoles, should be consistent with the requirements of the GB SQSS (e.g. in terms of permitted loss of power infeed) and the connections to the GB transmission system should be compliant with the GB SQSS generation connection criteria. An increase in the values of normal and infrequent loss risk will impact on both the relevant agreements and the level of investment in connection facilities.

With regard to exports across external interconnections, there are implications, which could appear to increase the maximum risk of demand loss on the GB system. However, such implications fall outside the scope of this report.

- It is the perceived frequency of occurrence of the secured event which, in turn, determines the frequency of occurrence of a loss of power infeed. Accordingly, continued application of the current GB SQSS planning criteria for the design of generation connections will mean that there will be no change in the frequency of loss of power infeed regardless of the threshold level of normal and infrequent infeed loss risk adopted.

Certain design differences will however emerge since, for instance, with say a single 1800MW unit connected to a single busbar section it will not be permissible to connect a further generating unit, regardless of size, on an adjacent busbar section unless two section switches and two busbar coupler switches are installed between busbar sections.

- The criteria and methodologies of the GB SQSS are concerned with the GB transmission system and, other than in the case of generation circuits, do not reach into other systems. Should an event external to the GB transmission system (e.g. the loss of a nuclear reactor or an external interconnection) lead to a loss of power infeed equal to the infrequent infeed loss risk at a frequency of occurrence inconsistent with the definition of infrequent infeed loss risk (e.g. more than around four times per year), additional measures would be required at the expense of the customer (e.g. generator) to enable NGET to achieve continued compliance with its statutory requirements. In this circumstance, the situation would require further review by the GB SQSS Review Group and this could determine that the customer (e.g. generator) would remain responsible for meeting any additional costs in accordance with the provisions of the variations to connection designs clause.

5.2 Operational Implications

- More primary and secondary response would be required, up to the new levels of normal and infrequent infeed loss risk, at all times when at least one such risk was actually present and generating on the system.
- Possibly some extra upward reserve would be required, to cover the greater possibility of large losses of generation within operating timescales of four hours.
- If the total volume of nuclear generation increases on the system, there will be an increase in the costs of downward regulation at low demand periods.

- If more response is held, then the maximum volume of generation armed on system-to-generator intertrips could be increased, above the current limit of 1320MW.

6 INFREQUENT INFEEED LOSS LISK

The planning and operational implications of a decision to implement the proposals to amend the threshold limit of the infrequent infeed loss risk are considered in more detail under the following three work areas:

- Cost-Benefit Analyses (CBA):
CBA were used to determine whether the benefits arising from implementation of the proposals would outweigh the associated costs.
- Market Analysis:
This analysis considered whether a decision not to implement the proposals would constitute due or undue discrimination against potential developers of large units.
- Technical Studies:
Dynamic simulation of an 1800MW loss event on the GB transmission system was used to establish whether insoluble problems in relation to system operation and security would result from implementation of the proposals.

Each of the above three areas are considered in detail in Annex 4, Annex 5 and Annex 6 respectively. The following paragraphs offer a summary for ease of reference.

6.1 Cost - Benefit Analyses

Table 1 provides a summary of the costs associated with the individual elements considered in the cost benefit analyses. The costs shown are in respect of a generic year 2020 – 2030.

Table 1: Summary of Cost Benefit Analyses

Item	Annual Benefits (£m)	Annual Costs (£m)
Carbon benefit of larger nuclear units	790.0	
Greater than 1320MW of generation on a double-circuit spur	7.5	
Fewer circuit breakers in substations	0.5	
Increase in primary response held		105.0
Increase in operating reserve		45.0
Increase in downward regulation costs overnight		10.0
Increased volume on inter-trips	10.0	
TOTAL	810.0	160.0

Table 1 indicates that in the central case of the cost benefit analyses the benefits of increasing the threshold levels of the normal and infrequent infeed loss risk is some five times the associated cost.

The cost-benefit analyses and findings were based on the following. Further detail is included in Annex 4.

- The largest benefit is due to the carbon benefit that would be derived from a fleet of six 1650MW nuclear units displacing an equivalent capacity of conventional generation. Carbon has been centrally priced at 25 £/T_CO2, which is the shadow price of carbon recommended by DEFRA for future appraisals. While the analyses are based on a fleet six nuclear units, the cost-benefit breaks even on the basis of two nuclear units.
- The three transmission-related benefits total £18m p.a. This figure may be slightly under-stated, but would, nevertheless, be insufficient to justify raising the infrequent infeed loss limit on its own.
- The dis-benefits (annual costs) are all associated with the operational cost of holding additional response and reserve. The costs are based on observed 2007 price levels. No persuasive argument is identified for centrally assuming price escalation across the next twenty years.

6.2 Market Analysis

6.2.1 Competition in Generation and Supply of Electricity

The Working Group noted and discussed the interaction between the infeed loss risk levels and facilitating competition in the generation and supply of electricity, and the impact of this interaction on the GB SQSS principles.

The Working Group noted that, by not changing the infeed loss limits to reflect the technology advancements in power stations, it may act against the objective of promoting competition in the market for electricity generation, for particular classes of power station.

By increasing the infeed loss risk thresholds and thereby treating the connection of different size generating units (up to the proposed maximum of 1800MW) in the same way, the three Transmission Owners and National Grid acting as GB System Operator would facilitate and promote competition in the generation of electricity as required by their duties under the Electricity Act.

6.2.2 Discrimination

Annex 5 considers the concepts of “due” and “undue” discrimination, competition and price discrimination and its application in the context of the GB SQSS. The following paragraphs provide a brief summary of key findings.

The proposed increase of the threshold levels for infeed loss risks sets a level playing field for all generation technologies wishing to connect to the GB transmission system, and thereby avoids discrimination between Users proposing to use different types of generation equipment.

Retention of the current threshold levels for normal and infrequent infeed loss risk would arguably have discrimination implications. If the current threshold levels were retained, a generator wishing to connect any single new generating unit of capacity greater than 1000MW would be required to meet the additional cost of holding response and reserve. This requirement would arise from the ‘variations to connection design’ provision of the current GB SQSS. On the basis of Table 1, these costs could amount to £150m p.a. for a

unit with an export capability of 1650MW (i.e. maximum infeed loss risk of 1800MW).

The question arises as to whether the current GB SQSS provisions could constitute due or undue discrimination against a particular class of generation technology. Again, in the case of current infeed loss risk threshold levels being retained, to argue that there is no undue discrimination under the present arrangements would require that the connection of single generating units in excess of 1000MW are 'special' and impose heavy costs on the operation of the GB transmission system which are, in some manner different (other than in size) that those created by smaller generating units. If this were the case, it might follow that it is reasonable to discriminate against the connection of such large single units by requiring the connecting generator to meet additional costs arising from the connection (i.e. in accordance with the 'variations to connection designs' clause) rather than those additional costs being spread across all users.

However, it does not appear that the connection of single generating units in excess of 1000MW is 'special' in as much as it does not create risks for system operation that are different in character (other than size) than those created by smaller units. Accordingly, a decision not to raise the normal and infrequent infeed loss risk thresholds, which would permit the connection of single units greater than 1000MW without recourse to the provisions of the variations to connection designs clause and associated payment of additional cost by the connecting generator, would appear likely to constitute undue discrimination.

6.3 Technical Studies

Annex 6 presents an investigation of the implications on the amount of demand and generation response required to ensure system security due to increasing the largest credible generation loss to 1800MW. The analysis was reflective of considerations arising from the events of 27/May/2008.³ The following paragraphs provide a brief summary of key findings.

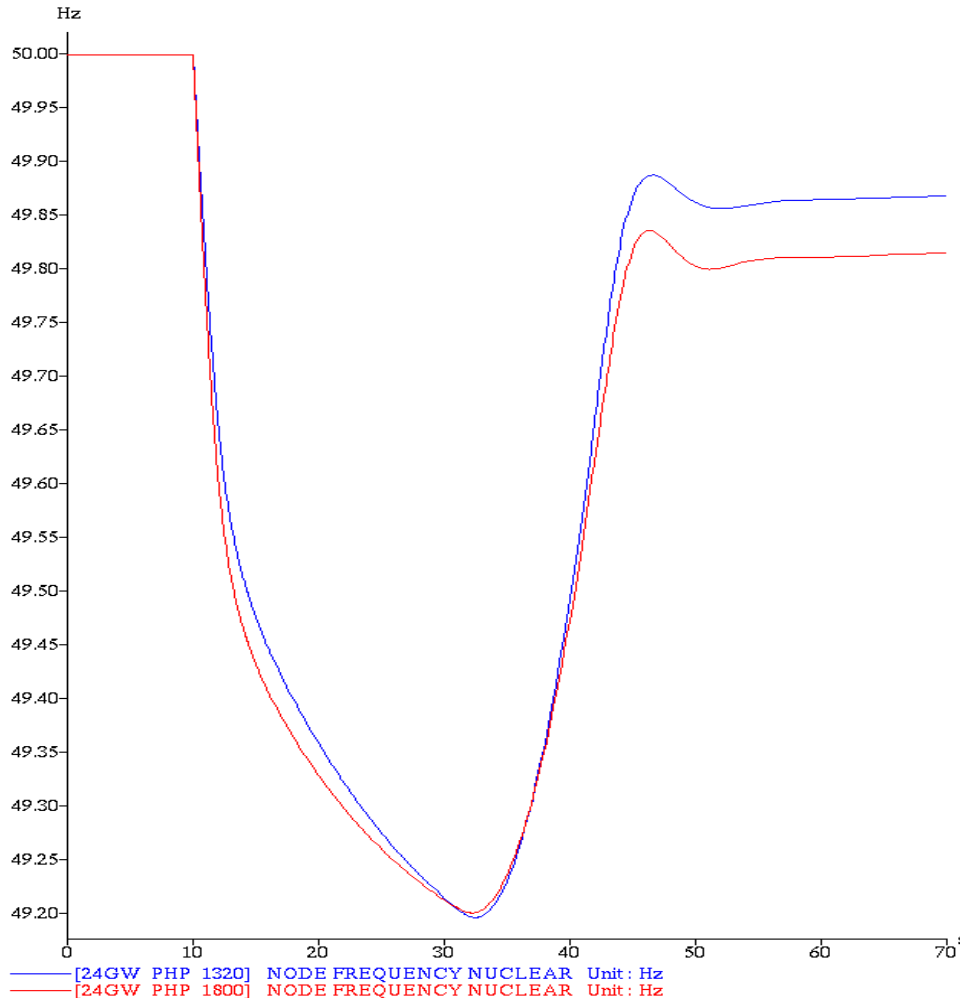
The difference between the current (1320MW) and proposed (1800MW) infrequent infeed loss risk is 480MW. With some 480MW of extra response (broadly as assumed within the cost-benefit analyses), system frequency performance shows a similar characteristic to current performance. The frequency dip can be contained to 0.8Hz. The rate-of-change of frequency (ROCOF) can increase by up to 40% but this is manageable assuming appropriate re-setting of certain ROCOF relays.

Figure 1 shows the frequency performance simulated for the GB transmission system, following an 1800MW loss of power infeed at the most onerous demand condition of summer minimum demand of 22GW (red trace). This is compared to a 1320MW loss of power infeed for the same system (blue trace). Please note that, in each case, the system was secured for the infeed loss i.e. an appropriate level of response was held. It can be seen that the performance of the system with an increased infrequent infeed loss limit is broadly similar to the performance of the present system. In both cases the

³ On 27/May/2008 at 1134–1136 am, the GB transmission system suffered the loss of some 1600MW of power infeed from Longannet and Sizewell B within 2 minutes. The system frequency fell to 48.8Hz, its lowest level for twenty years, and Low Frequency Demand Disconnection relays correctly operated to trip some 900MW of demand to secure the system.

minimum frequency is 49.2Hz, recovering to above 49.5Hz which is well within 60 seconds of the infeed loss occurring.

Figure 1: Comparison of Systems Secured for a Loss of Power Infeed of 1320MW and 1800MW.



The studies do raise concerns including: in relation to the quality of windfarm responsive capability; and in relation to existing ROCOF relay settings. However, these concerns are already being pursued in the appropriate forums e.g. under the Grid Code. These concerns, which are already present for a 1320MW loss, would be exacerbated by, rather than caused by, an 1800MW loss.

For the avoidance of doubt, this report at no point proposes or discusses any change to the statutory requirements for system frequency performance. The technical studies demonstrate that, for an instantaneous 1800MW loss of power infeed those requirements will continue to be met provided that suitable extra response is held. The holding of extra response to cover an infrequent 1800MW infeed loss risk will also improve the frequency performance in respect of the more frequent (normal) loss of power infeed less than 1800MW.

7 GB SQSS PARAGRAPH 2.6.3

Paragraph 2.6.3 of the current GB SQSS reads:

“following a fault outage of any single generation circuit or single section of busbar or mesh corner, the loss of power infeed shall not exceed the normal infeed loss risk”

Amongst other things, this paragraph limits the size of a generating unit, or group of generating units, connecting to a single busbar section to a maximum of 1000MW (i.e. the current normal infeed loss risk). With the advent of larger unit sizes (e.g. 1650MW which pose an 1800MW loss of power infeed risk), this limit will need to be increased accordingly.

The secured events considered in the current paragraph 2.6.3 have, for a number of years, been considered as ‘normal’ events and accordingly the permitted loss of power infeed for such events was set at the ‘normal infeed loss risk (1000MW). However, it is now argued that such events should no longer be regarded as ‘normal’ but should rather be classified as infrequent (i.e. with a frequency of occurrence in the region of four times per year) in recognition of the following statistical evidence:

- National Grid fault statistics show that just 9 busbar faults occurred over the two years 2006 and 2007. These 9 faults occurred across a population which is conservatively estimated at 939 busbars. This population estimate is based on 313 substations x 3 busbar sections or mesh corners per substation (both of which are reported as ‘busbar faults’). This represents one busbar fault per 200 years (i.e. 9 faults / (2 years x 939 busbars) = 0.005 faults per busbar per year or one fault per busbar in 200 years).
- National Grid do not routinely keep statistics of generation circuit faults. However, the generation circuit fault rate may reasonably be assumed to be substantially less than the trip rate of the generating units which they connect to the GB transmission system. National Grid reports 143 single transmission circuit faults over the two years 2006 and 2007. These faults occurred across a population of 13,963km of circuit. Hence, the single circuit fault rate is in the order of one fault per km in 200years (i.e. 143 faults / (2 years x 14000 km) = 0.005 faults per km per year or one fault per km of single circuit in 200 years).

If it is assumed that, say, ten 1320-1800 generating units connect to the GB transmission system by 2030 (this assumption of 10 is cautiously set above the 6 new nuclear units assumed in the cost-benefit analysis), then the busbar sections and generation circuits associated with these units will experience a total of $10 \times \{1/200 + 1/200\} = 0.1$ faults per year. This is almost negligible, in the context of the current interpretation of a count of ‘permissible’ infrequent loss events of around four times per annum. The incidence of connection of single generating units or groups of generating units to, say, single busbar sections could increase to 400 before the frequency of occurrence of the loss of power infeed reached four per year.

Accordingly, in the context of the GB SQSS, the frequency of occurrence of the secured events of paragraph 2.6.3 may reasonably be described as ‘infrequent’ rather than ‘normal’.

To accommodate the larger units and in recognition of the frequency of occurrence of the secured events, it is therefore recommended that paragraph

2.6.3 is reworded to refer to the infrequent infeed loss risk rather than the normal infeed loss risk:

“following a fault outage of any single generation circuit or single section of busbar or mesh corner, the loss of power infeed shall not exceed the infrequent infeed loss risk”

The effect of this change proposal will be to increase the limit under paragraph 2.6.3 to 1320MW immediately followed by a further increase to 1800MW from the Infeed Change Date (Section 9 refers).

8 NORMAL INFEEED LOSS RISK

Following the above proposed change to SQSS clause 2.6.3, it is the case that the 'Normal Infeed Loss Risk' will not formally be referenced in any clause of the GB SQSS. This recognises that the term is currently only referenced in the planning criteria of Section 2 of the GB SQSS. Operational criteria of Section 5 are not prescriptive as to the precise risks being secured at any time (Section 3.2.3 of his report refers).

Nevertheless, the concept of the 'Normal Infeed Loss Risk' remains significant for the GB SQSS. Its definition remains:

“that level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5Hz”.

The above definition provides strong guidance to the operator such that where the frequency of occurrence of a secured event may reasonably be regarded as 'normal', the loss of power infeed resulting from the secured event should not cause the frequency to deviate outside the statutory limits of 49.5Hz to 50.5Hz. In planning timescales, the planner designs the system, in recognition of the perceived frequency of occurrence of different secured events, such that sufficient investment is made to enable the system operator to meet statutory and other obligations. For instance, the planner would not permit the connection of generation such that it posed a frequent loss of power infeed risk (i.e. normal circumstance) in excess of the defined level normal infeed loss risk.

In addition, events outside the GB transmission system can also pose a loss of power infeed risk (e.g. the fault outage of external interconnections). External interconnections are covered by separate agreements which will normally be consistent with the GB SQSS – Section 5.1 refers) and the level of response and reserve require. While secured events involving such external influences fall outside the planning criteria of the GB SQSS, they will still be taken into account by the operator when considering the 'the most onerous loss of power infeed' under 'prevailing system conditions' (section 3.2.3 refers).

The defined term, 'normal infeed loss risk' is: consistent with statutory requirements on frequency; parallels the definition of 'infrequent infeed loss risk'; and provides a useful benchmark for considering the need or otherwise for holding additional response and reserve (e.g. due to external influences).

For these reasons, it is proposed that the definition of the normal infeed loss risk is retained in the GB SQSS.

The findings, discussed in Section 6 of this report, provide a sound basis for increasing the threshold level of the infrequent infeed loss risk in the GB SQSS. Assuming that the infrequent infeed loss risk is increased to 1800MW, the following three options for setting the threshold level of the normal infeed loss risk within the planning criteria of the GB SQSS are considered:

A - Normal Infeed Loss Risk remains at 1000MW

The current wording of the GB SQSS works with this level despite the presence of a 1260MW risk from Sizewell B on the system. Accordingly, the current wording will work with larger risks on the system.

B - Hybrid Level – Normal Infeed Loss Risk raised to (say) 1320MW

C – Normal Infeed Loss Risk raised to 1800MW (i.e. the proposed Infrequent Infeed Loss Risk level)

It is possible that connection of a fleet of large units may result in 1800MW trips at a rate which may not reasonable be considered as infrequent. In this event, the threshold level of the normal infeed loss risk would need to be increased to 1800MW at some time in the future. It may be argued that it is appropriate to increase the threshold level of the normal infeed risk at the same time that the infrequent infeed loss risk is increased to 1800MW.

The advantages and disadvantages of the above three options are summarised in Table 2 below:

Table 2: Normal Infeed Loss Risk – Comparison of Options

Option	Advantages	Disadvantages
Option A: Leave at 1000MW	Minimises operational on-cost	Might lead to an unacceptable high count of frequency excursions below 49.5Hz
Option B: Hybrid Level	Retains the optimality, in terms of response holding, of the dual response standard	Lack of objective rationale for any particular setting
Option C: Reset to 1800MW	Pre empts the later need to change should it be found that large units trip at a rate which may not reasonably be considered as infrequent.	Loses the optimality, of permitting a frequency excursion outside the statutory 49.5Hz (-1%) limit solely for an infrequent loss of power infeed.

The preferred option is Option B. Accordingly, it is recommend that the threshold level of the normal infeed loss risk is raised from 1000MW to 1320MW. The arguments in favour of this recommendation are summarised in the following paragraphs.

The normal infeed loss risk is the level of power which is covered, operationally, by frequency response to avoid a frequency deviation on the GB transmission system of more than 0.5 Hz. It is therefore important that the figure remains reflective of the normal operational running conditions on the GB transmission system. Option B (Hybrid Level) represents a proportional and appropriate level against which frequency response should be held by the GBSO, given the statutory obligations and the associated proposed change in the infrequent infeed loss risk level.

The revised figure would ensure that the number of excursions outside the normal infeed loss risk is comparable with the existing levels and would not represent an increase in the operational risk on the GB transmission system.

A fundamental difference between the normal and infrequent infeed loss risks is their permitted frequency of occurrence. Whilst the former may be regarded as a normal occurrence, the latter is regarded as exceptional in that it occurs only infrequently. The simplified analysis of Annex 6 (appendix 6.2), confirms that, if the GB transmission system is being operated with the required extra response to contain frequency to within 49.2Hz following a loss of power infeed of 1800MW, then a loss of power infeed of between 1440MW and 1670MW will cause a frequency deviation to 49.5 Hz. (Note: the actual calculations were based on a 1440MW loss of power infeed at the time of system maximum demand, and a 1670MW loss of power infeed at the time of system minimum demand. The 1670MW at minimum demand recognises the relatively high level of primary response holding at the minimum demand condition). It follows that increasing the threshold level of the normal infeed loss risk to 1320MW will guarantee that 1320MW loss of power infeed events will not lead to any excursion outside the statutory limits of 49.5–50.5Hz.

The argument in favour of Option C is quite strong since it is possible that experience will require the normal infeed loss risk to be raised to 1800MW at an as yet undefined date in the future. However, to raise the level earlier than necessary could lead to a lack of transparency and a possible mismatch between planning and operating the GB transmission system. It is considered more appropriate that the level of the normal infeed loss should be further reviewed when a high count of loss of power infeeds of the order of 1320MW to 1800MW are experienced or anticipated.

9 IMPLEMENTATION DATE

The question arises as to what date should the threshold levels of infeed loss risks be reset, and/or against what trigger events? It is noted that it is appropriate to plan the development of the GB transmission system on the basis of the revised levels of infeed loss risk (i.e. in accordance with Sections 2 to 4 of the GB SQSS) in advance of the real time operation of the GB transmission system on the basis of revised levels of infeed loss risk (i.e. in accordance with Section 5 of the GB SQSS).

The choice of implementation date for any change to the threshold levels of the normal and infrequent infeed loss risk is a function of the following two hypothetical developments which may occur during the next decade:

Case A

For example, South Humberbank currently has a transmission entry capacity (TEC) of 1320MW which is connected by a double-circuit spur of around 20km in length. In the event of an application being received in 2010 for an extra 300MW of generation for connection in 2013, the following questions arise. Should the response holding be increased from 2013 and the additional capacity allowed on to the system without recourse to the variations to connection designs clause? Or should the generator be charged (through the provisions of the variations to connection designs clause) for the extra 300MW of response required pending the commissioning of a large generation unit which would trigger the increase in the threshold level of the infrequent infeed loss risk?

Case B

If GSR007 recommendations are approved and implemented to coincide with the forecast commissioning of a first new nuclear unit on a specified date of, say, 1st January 2018, then in the event of an application being received in 2011 for the connection of a 1500MW super-critical unit in 2015, the following question arises. Should the generator be charged (through the provisions of the variations to connection designs clause) for the extra response required in the first three years of operation or should the implementation date for the increase in the threshold level of infrequent infeed loss risk be brought forward?

An important issue is the operational start date, which is the date from which the GBSO would hold additional response; the costs of which would be socialised. It can be argued that the planning of the system on the basis of the revised threshold levels for normal and infrequent infeed loss risk would commence as soon as the Authority endorses the recommendations of GSR007, in recognition of the limited life of the current limits. However, the Authority may endorse a separate and specific planning start date. For instance, planning performed before (say) 1/1/2012 is conducted on the basis of the current levels of infeed loss risk and planning after 1/1/2012 is conducted on the basis of the new levels of infeed loss risk.

In view of the above, the following options are available:

Option A1

Plan to 1800MW from the time the Authority decision to approve GSR007 recommendations is given (e.g. 1st April 2010). Hold appropriate increased response and reserve operationally and socialise the cost as soon as an 1800MW generation risk (transmission or generation) commissions.

Option A2

Plan to 1800MW from the time an Authority decision to approve GSR007 recommendations is given (e.g. 1st April 2010). Hold appropriate increased response and reserve operationally and socialise the cost as soon as an 1800MW generation or external interconnection risk commissions, but do not do so for a transmission risk (which is a lower order probability).

Option A3

Plan to 1800MW from the time an Authority decision to approve GSR007 recommendations is given (e.g. 1st April 2010). Hold appropriate increased response and reserve operationally and socialise the cost as soon as an 1800MW generation risk commissions, but do not do so for a transmission or external interconnection risk (which are lower order probability). Sub-options include either derogating or charging-out a transmission risk, assuming the development causing the transmission risk commissions before the 1800MW generation risk commissions.

Option B

The Authority determines that it expects the first unit in excess of 1000MW (whether nuclear or super-critical coal) to commission on, say, 1st April 2016. Prior to this date, any development posing a loss of power infeed risk in excess of 1320MW is required to pay for the extra response required. After this date, the cost the extra response is socialised.

Option C

The Authority notes that the cost-benefit does not support socialising the response on-cost until the second unit in excess of 1000MW commissions. Accordingly, the Authority determines that the infeed loss risks should not be

increased until such date as the second unit in excess of 1000MW commissions. Prior to this date, any development posing a loss of power infeed risk in excess of 1320MW is required to pay for the extra response required. After this date, the cost the extra response is socialised.

The following paragraphs briefly consider each of the above options:

Option A1

There is no cost-benefit case for holding extra response against a transmission risk. Such a risk, for example 1800MW of generation capacity connected via one double-circuit spur, is expected to trip no more frequently than once every five years. In these low risk circumstances the cost of £160m pa of extra response cannot be justified and it would therefore be inappropriate to permit such a generation connection or to socialise the cost. Accordingly, Option A1 is not supported.

Option A2

Option A2 differs from Option A3 solely in respect of the case of the commissioning of an external interconnection with a capacity in excess of 1320MW. It is argued that, whereas it is reasonable and non-discriminatory for of the cost of extra response to be socialised in the case of the connection of a larger generation unit, this should not apply in the case of the connection of a potential new external interconnection earlier than the connection of a new generating unit in excess of 1320MW. However, it is noted that there are currently no external interconnections of infeed greater than 1200MW with either a planned or proposed connection to the GB transmission system within the next decade.

Option A3

Option A3 permits flexible planning of the system, with regard to 1800MW risks, over the next few years, during which the exact commissioning date (if any) of a risk in excess of 1320MW will remain uncertain. This option permits sensible holding and charge-out of response, when such a risk eventually (if ever) commissions.

Option B

Option B fixes an implementation date and thus creates clarity for the transmission planning process and for generation developers. The precise date on which risks in excess of 1320MW will be permitted would be known. However, in reality the possible commissioning date of any risk in excess of 1320MW is too uncertain at present for the option to be favoured. For example, if an implementation date of 1st April 2016 were set, and in the event no large units in excess of 1320MW were to commission before 2021, the operator may need to hold additional response for five years just to mitigate against a few transmission risks posed by generation groups in excess of 1320MW connecting to double circuit spurs.

Option C

Option C gives a poor economic case to develop any first unit in excess of 1320MW, since the generator will be required to bear the extra response cost until a second unit commissions. The option gives an excessive incentive to attempt to commission the first two nuclear or large-coal units simultaneously, which would increase the difficulties associated with developing a new technology, and which would not be sensible on system reliability grounds. Moreover, simultaneous commissioning is not practical between two separate generators, who may well be competing to bring such developments to market.

Based on the above considerations Option A3 is selected as the preferred choice.

10 SUMMARY OF WORKING GROUP RECOMMENDATIONS

The Infeed Loss Working Group recommends that the GB SQSS be amended such that:

- The threshold level for the 'Normal Infeed Loss Risk' shall be retained at its current level of 1000MW until the 'infeed change date' (see below) thereafter the level should be increased to 1320MW;
- The threshold level for the 'Infrequent Infeed Loss Risk' shall be retained at its current level of 1320MW until the 'infeed change date' (see below) thereafter the level should be increased to 1800MW;
- The 'Infeed Change Date' shall be the date on which a single generating unit, CCGT Module, boiler or nuclear reactor of Registered Capacity greater than 1320MW connects to the GB transmission system and commissions; and
- Paragraph 2.6.3 of the current GB SQSS shall be modified to refer to the 'infrequent infeed loss risk' rather than the 'normal infeed loss risk'. Accordingly the amended paragraph would read:

“following a fault outage of any single generation circuit or single section of busbar or mesh corner, the loss of power infeed shall not exceed the infrequent infeed loss risk”

The Government has stated on a number of occasions over the years 2007 and 2008 that it believes it desirable that the GB generation market develops to deliver a fleet of new nuclear units within the next ten years. At least one new nuclear technology under consideration involves units in excess of 1320MW. The recommendations of this report facilitate this development, and permits competition in new nuclear technologies, by removing the very material risk of response charge-out, which is present in current arrangements.

11 IMPACT ON GB SQSS

Change proposals to the drafting of the GB SQSS arising out of the Working Group recommendations are presented in Annex 3 to this report. The change proposals affect just four paragraphs of the current GB SQSS.

12 IMPACT ON INDUSTRY DOCUMENTS

12.1 Impact on Core Industry Documents

The Working Group concludes that this GSR007 has no impact upon Core Industry Documents. The actual levels of infeed loss risks are not mentioned in the: BSC; CUSC; STC; or Grid Code.⁴

12.2 Impact on Other Industry Documents

GSR007 has no impact upon other Industry Documents, for the reasons given individually below:

12.2.1 Balancing Principles Statement

National Grid's Balancing Principles Statement states the principles against which Balancing Services are procured. There is no need for new mechanisms of purchase following GSR007, and so there is no impact on Balancing Principles.

12.2.2 Procurement Guidelines

National Grid's Procurement Guidelines state the manner in which Balancing Services are purchased. There is no need for new mechanisms of purchase following GSR007, and so there is no impact on Procurement Guidelines. Of course, greater volumes and costs of purchase will be described in annual Procurement Guidelines reports.

12.2.3 Use of System Charging Methodology

National Grid's Statement of the Use of System Charging Methodology merely states that the BSUoS charge ('Balancing Services Use of System') will be set daily, according to National Grid's outturn costs for balancing the system. GSR007 merely increases the volumes and costs of response and reserve flowing through BSUoS, and does not change the form of BSUoS, and accordingly there is no impact on the Use of System Charging Methodology.

13 ASSESSMENT AGAINST GB SQSS PRINCIPLES

The recommendations of this report would support the following GB SQSS principles:

- *The development, maintenance and operation of an efficient, economical and coordinated system of electricity transmission*

The Working Group has considered these principles within the cost-benefit of Annex 4. Increasing the level of infeed loss risks will increase the costs of operating the power system, by £160m pa of response and reserve costs. However, permitting the connection of a fleet of six new nuclear units will save

⁴ On 25th September 2008, the Working Group debated the wide issue that the criteria and methodologies of the GB SQSS are concerned with the GB transmission system and, other than in the case of generation circuits, do not reach into other systems. Accordingly there is no specific obligation on parties to limit the maximum generation risk of loss of infeed. This could be rectified through a Grid Code obligation on Generators and other parties to notify the GBSO of all mechanism which could lead to large loss of power infeed and an obligation on the GBSO to take due account of all infeed risks notified. However, the Working Group concluded that this would fall outside the scope of GSR007.

some 32 MT_CO2 pa of carbon emissions from the electricity sector, yielding a saving centrally estimated at £790m pa. In addition, there will be some £20m pa of saving on transmission expenditure. Hence the review request leads to an overall benefit.

- Ensure an appropriate level of security and quality of supply and safe operation of the GB Transmission System

The technical studies described in Annex 6 show that increasing the infeed risks up to 1800MW causes no change to the security or quality of supply of the GB transmission system. This is based on the assumption that sufficient additional response is held at all times.

- Facilitating effective competition in the generation and supply of electricity

The discussion of discrimination in Annex 5 leads the Working Group to conclude that there are no discrimination issues in raising the level of the infeed loss risks, and that this obviously facilitates/increases competition in market place. Indeed, to maintain the infrequent infeed loss risk at 1320MW would discriminate against potential developers of generating units greater than 1320MW, which are a realistic prospect.

The proposed increase of the threshold levels for infeed loss risks will sets a level playing field for generators seeking to use all generation technologies and wishing to connect to the GB transmission system; facilitating effective competition in generation and supply of electricity and avoiding discrimination.

14 ENDORSEMENT BY GB SQSS PARTIES

This section sets out the analysis and impact assessment (“Assessment”) provided by GB SQSS Parties.

14.1 National Grid Electricity Transmission (NGET) Assessment

NGET in its roles as Transmission Owner (TO) for England and Wales and GB System Operator (GBSO) believes that the proposed GB SQSS change proposals will better facilitate the GB SQSS Principles, laid out in Section 10 of this report. National Grid believe that the extra required response can be procured at economic cost, such that there is no impact on the quality of system frequency. The consequent changes to the planning of transmission will lead to modest capital savings in certain cases, at no degradation to standards of service.

14.2 Scottish Hydro-Electric Transmission Limited (SHETL) Assessment

The GB transmission system is operated by the GBSO, who has the responsibility to assess the potential frequency excursions arising from proposed new loss of infeed limits. A modelling exercise for the GB transmission system has shown that a potential loss of 1800MW can be accommodated, provided that sufficient generation response and reserve is held.

The SHETL system, as with the transmission systems of all GB Transmission Owners, is planned such that the requirements of the GB SQSS and STC codes are met. With the proposed increase in the threshold levels for normal

and infrequent loss of power infeed to 1320MW and 1800MW respectively, new connection design proposals will still be assessed using the existing criteria for network performance. In certain circumstances the new limits will allow greater efficiency in terms of network design and equipment used (e.g. number of breakers required in substation design). Hence the increases in the levels of loss of power infeed will have no adverse impact on the SHETL asset as the performance requirements remain unchanged.

SHETL has identified no adverse technical, economic or environmental planning impact on its transmission network resulting from the proposed changes.

14.3 SP Transmission (SPT) Assessment

The most significant impact of increasing the levels of normal and infrequent infeed loss risk is on the GBSO, who has to provide increased levels of response. SPT owns, but does not operate, a transmission system and is therefore is not directly affected by this aspect. A change in level of infeed loss risk may have implications for future infrastructure or connection designs and could lead to some capital cost savings. However, such savings are expected to be modest in comparison to, for example, the increased operational costs arising from an increase in the infeed loss limits. Therefore, it is SPT's assessment that the SQSS changes proposed in this Consultation Document will not have a significant impact on SPT's business.

ANNEX 1: GB SQSS REVIEW REQUEST FORM (GSR007)

GB SQSS REVIEW REQUEST

DATE: 22/02/2008

1. Title of review request
Review of Infeed Loss Limits
2. Name of Proposer (include name of contact person)
EDF Energy plc, Denis Linford, Director of Regulation
3. Proposer Contact Details¹
40 Grosvenor Place, London, SW1X 7EN, telephone 0207 752 2200, email Denis.Linford@edfenergy.com , FAX 020 7752 2128, mobile telephone 07875 110051
4. Description of issue(s)/Defect(s) to be addressed by the request
<p>Currently, the GB SQSS limit for Normal Infeed Loss Risk is set out in sections 2.6.1 to 2.6.3 of the SQSS document and is the level of loss of power infeed risk covered by fault outage on any single transmission circuit, generation circuit and planned or fault outage on any single section of busbar or mesh corner. This currently stands at 1000MW. The SQSS Infrequent Infeed Loss Risk is set out in sections 2.6.4 to 2.6.6 of the SQSS document and is the level of loss of power infeed risk which is covered following the concurrent fault outage of any two transmission circuits, any two generation circuits on the same double circuit overhead line, any single busbar section circuit breaker or mesh circuit breaker, or the loss of any single transmission circuit or section of busbar during the planned outage of any other single transmission circuit or busbar). This currently stands at 1320MW.</p> <p>The definitions of each limit include the words "until reviewed" indicating that these parameters are designed to be changed from time to time. These limits have not been changed since at least 1990.</p> <p>The infeed limits specified in the GB SQSS were established for the system that existed at that time and have evolved as the characteristics of generation and the transmission system have evolved. The GB electricity industry is facing substantial investment in new generation capacity over the coming decade as a significant proportion of the current generation fleet needs to be replaced.</p> <p>It is likely that future designs for thermal generation plant will not be consistent with current SQSS limits. This could discriminate against more efficient large plant and will almost certainly discriminate against the most efficient options for medium-term nuclear build. The designs currently being considered in the nuclear regulators' GDA process all have generating unit sizes greater than 1000MW.</p> <p>The current infeed limits are therefore no longer consistent with the range of generation technologies that could be built in Great Britain in the foreseeable future and consequently a review of the infeed limits is now required.</p>

5. Description of the review request, its nature and purpose
<p>The review request aims to increase the Normal and Infrequent Infeed Loss Limits such that an alternator of greater size than is currently offered a standard connection can be connected to the GB transmission system under a standard bilateral connection agreement. This will reflect the economic and social desirability of efficient forms of large scale power generation and ensure that the cost allocation of reserve provision is also consistent with this. We do not consider that Design Variation Connections would adequately resolve the existing barrier to efficiency.</p> <p>We suggest the following as possible areas for consideration by a review working group:</p> <ul style="list-style-type: none">▪ Analysis of balancing services associated with having several larger plant connected to the system relative to the possible characteristics of the system, including other technologies and deeper interconnection, around 2020 and subsequently.▪ Analysis of the efficiency benefits of connecting larger plant to the system.▪ Analysis of barriers to efficient entry for larger plant.▪ Assessment of likely changes in reserve requirements as a result of expected evolution of the GB generation mix to around 2020 and in subsequent years.▪ Analysis of the benefits that many large steam turbine plants would have, including carbon emissions avoidance and security of supply issues compared to a reliance on gas-fired generation.
6. Impact on the GB SQSSⁱⁱ
6 (a) Parts of the GB SQSS that require amendment to give effect to the request
<p>Normal Infeed Loss Limit and Infrequent Infeed Loss Limit to be reviewed to properly and efficiently accommodate new generation technologies with the potential for installation in Great Britain beyond 2017. This will require an amendment to the levels of 'Normal Infeed Loss Limit' and 'Infrequent Infeed Loss Limit' as set out in Section 7 'Terms and Definitions' in the GBSQSS.</p>
6 (b) Parts of the GB SQSS that would otherwise be affected by the request
<p>Consequential changes may be required to the definitions of infeed limits.</p>
6 (c) Nature and contents of amendments or effects
<p>To increase the Normal and Infrequent Infeed Loss Limits such that generation units with large alternators of up to 1800MW can be connected to the GB transmission system in a manner that is consistent with SQSS standards.</p>
7. Justification of the request, giving the background thereofⁱⁱⁱ
<p>Historically, as technological evolution has brought larger generating units onto the</p>

system, the SQSS has also evolved to accommodate these units, for example, the IFA interconnector (where co-entrenchment of dipoles means up to 1000MW could be lost in one instance) and the introduction of the 1320MW Sizewell B plant. Thus, SQSS limits in the past have not acted as a block on the application of new technologies; they have evolved so as to remain reflective of the then current generation technologies.

Changes in international generation designs now mean that standard alternator sizes can exceed 1000MW (the Normal Infeed Loss limit). Projects with turbines exceeding 1000MW are being developed and are under construction or are already operating in Europe, including :

- 2 x 1050MW lignite plant in Neurath, Germany expected for 2009/10
- 1100MW coal plant in Datteln, Germany expected 2010
- 1450MW upgrade of nuclear plant in Sweden and 1650MW nuclear plants in France and Finland
- 4 x 1450MW nuclear plants are operating in France.

The balance of generation plant connected to the GB Grid and the nature of the Transmission Network itself are both changing, and the Grid Rules are altering to recognise these changes. For example :

- In the latest forecast for incentivised balancing costs, the SO expects additional reserve and frequency response costs of £10m to accommodate 500MW extra wind capacity in 2008/9. These costs have been charged to users on a £/MWh basis, as is always the case with reserve costs and other elements that make up BSUoS. With total wind capacity expected to exceed 20 GW by 2020, significant increases in required levels of reserve as well as far greater utilisation of reserve options of fast-response plant and of pumped storage are expected.
- The Offshore SQSS accommodates offshore wind transmission connections, which do not have to be fully redundant. A similar situation prevails in Scotland (as a system as a whole) with some boundary circuits having derogations¹ against the SQSS and many generation connections in SHETL transmission regions being non-standard in relation to SQSS.

These examples help illustrate how Grid Rules are not static but develop over time as the GB power system undergoes significant change, and how current infeed limits in SQSS do not fully reflect the value to society of both system security and large volumes of low carbon generation. So that the transmission licensees can meet their statutory duty to develop, maintain and operate an efficient, economical and coordinated system of electricity transmission, the transmission system must be fit for purpose for all its users. As users of the system look to invest in the latest

¹ http://ofgem2.ulcc.ac.uk/temp/ofgem/cache/cmsattach/8777_19604_NGT.pdf?wtfrom=/ofgem/whats-new/archive.jsp (Paragraph 7)
http://ofgem2.ulcc.ac.uk/temp/ofgem/cache/cmsattach/7018_national_grid.pdf?wtfrom=/ofgem/whats-new/archive.jsp (Item VI on page 4)

generation technologies, so the transmission system and the rules that govern it need to evolve to accommodate these new technologies.

Furthermore, the transmission licensees are obliged to facilitate competition in generation. The SQSS currently represents a barrier to entry for some new generation technologies.

The transmission licensees are also required to ensure an appropriate level of security and quality of supply and safe operation of the transmission system. Aside from ensuring that the transmission network itself is secure, safe and reliable, the transmission licensees must also facilitate the development of generation assets which contribute to the overall security of the GB electricity supply industry. Where an unmodified SQSS creates a barrier to efficient entry of new generation technologies, there is a risk that medium to long-term security of supply will be threatened. Also, future increases in transmission interconnection capacity may leave current SQSS limits obsolete.

Facilitating secure supply and contributing to meeting medium-term carbon reduction targets are key objectives of energy policy. It is likely that large plant such as nuclear reactors will play a significant role in meeting these security of supply and carbon reduction goals. This is demonstrated in the 2008 Government White Paper on Nuclear Power, which states that 'without nuclear power, the UK would depend on fewer technologies which could expose us to greater risks to the security of our energy supplies' and that 'the Government believes nuclear power should be able to play a part in the UK's future low-carbon economy'. There is a risk that, under the current SQSS, new nuclear plant would be rendered less economic, resulting in a lesser role for nuclear in the future energy mix, greater dependence on gas-fired generation, lower security of supply and higher carbon emissions.

8. Potential impact of the request on other Core Industry Documents^{iv}

None identified.

9. Potential impact of request on relevant computer systems^v

None identified.

Guidance notes

- (i) Please include address, contact telephone/fax number and optionally, a contact email address.
- (ii) Impact on the GB SQSS - Where possible, give an indication of those parts of the GB SQSS which, in the opinion of the Proposer, would be likely to require amendment in order to give effect to (or would otherwise be affected by) the request and an indication of the nature and contents of those amendments or effects (including, where relevant, any need for the establishment of new, or removal of existing GB SQSS criteria and methodologies).
- (iii) Justification - Please give reasons why you believe that the request would better facilitate achievement of the GB SQSS objectives as compared with the then current version of the GB SQSS, together with background information in support thereof. If more space is needed you can use additional sheets of paper which should be attached to this form.
- (iv) Core Industry Documents include but not limited to The Grid Code, System Operator – Transmission Owner Code and the Connection and Use of System Code
- (v) Where possible, please give an indication of the potential impact of the request on relevant computer systems and processes used by the Transmission Licensees.
- (vi) Incomplete forms will not be processed. The Proposer may be asked to clarify any information that is not clear; the Proposer's attention is drawn to clause **<Error! Reference source not found.** of the GB SQSS governance document.

ANNEX 2: WORKING GROUP TERMS OF REFERENCE AND MEMBERSHIP

GB SQSS Review Group – Infeed Loss Limits Working Group

Terms of Reference

Terms of Reference

It was agreed at GB SQSS Review Group meeting on 10th April 2008 that a Working Group would be established. The Working Group would be tasked with reviewing of the normal infeed loss limits and infrequent infeed loss limit in light of the new generation technologies which are proposed to be connected to the Transmission System in future years in order to meet Energy Policy objectives. The terms of reference for the Working Group are:

1. Review the normal and infrequent infeed loss limit, identify the maximum loss of each limit
2. Consider largest loss in terms of both Planning and Operational timescales
3. Identify and assess technical implications of increasing the limits
4. Identify and assess security of supply effects
5. Consider the commercial implications e.g. ancillary services
6. Evaluate applicable economic and environmental costs and benefits
7. Recommend changes required to GB SQSS
8. Identify consequential changes which may be required to other industry codes
9. Liaise and consultation with industry stakeholder as appropriate

Out of Scope

Connection of large volume of demand and interconnectors.

Working Group Members

Members of the Working Group will be as follows:

<i>Chair</i> Mike Lee (National Grid)	<i>Secretary</i> Lilian Macleod (National Grid)
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<i>National Grid Representatives</i> Ben Marshall Sam Matthews Paul Plumptre	<i>Authority Representative</i> Bridget Morgan
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<i>SPT Representatives</i> Cornel Brozio	<i>SHETL Representative</i> Richard Lowe
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Industry Representatives
Sebastian Eyre (EDF Energy)
Claire Maxim (E.ON UK)
John Morris (British Energy)
James Suckley (EDF Energy)

Meeting Dates

The Working Group meetings will be held at National Grid House, Warwick. The meetings have been scheduled for the following dates:

- 12th June 2008
- 17th July 2008

Timeline

- Draft Working Group Report – October 2008 GB SQSS Review Group Meeting (14/10/2008)

- Final Working Group Report – January 2009 GB SQSS Review Group Meeting (15/01/2009)
- Consultation Paper – circulated to the industry by beginning of February 2009
- Report to Authority – to be submitted to Ofgem by 1st June 2009

ANNEX 3: CHANGE PROPOSALS TO THE GB SQSS

The Working Group's proposed change proposals to implement the recommended changes to the GB SQSS are given below. Two alternate change proposals relating to definitions were considered, namely: style A3; and style B. Style A3 is recommended. Consideration of style B is included here for completeness only. In addition, recommended change proposals to paragraph 2.6.3 are also included.

Drafting for GSR007 Implementation A3

To achieve implementation style A3, the following re-drafting is proposed:

Change the definitions of Normal and Infrequent Infeed Loss Risk to:

Normal Infeed Loss Risk:

*That level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5Hz. Until the **Infeed Change Date**, this is 1000MW. After the **Infeed Change Date**, this is 1320MW.*

Infrequent Infeed Loss Risk: *That level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5Hz to 50.5Hz for more than 60 seconds. Until the **Infeed Change Date**, this is 1320MW. After the **Infeed Change Date**, this is 1800MW.*

Add a new definition for the Infeed Change Date:

Infeed Change Date: *The date on which a single generating unit, CCGT module, boiler or nuclear reactor of Registered Capacity greater than 1320MW connects and commissions to the GB transmission system.*

Drafting Commentary:

- This drafting achieves the desired effect in the standard case where new nuclear units connect around 2017 (as currently contracted) and a background of no further applications for the connection of units in excess of 1320MW being received before. There are no planning issues prior to 2017 and the GBSO increases the response holding when the nuclear connects (2017). In the event of a delay in the connection of the new nuclear power stations, the need for holding additional response and the timing of the Infeed Change Date would be deferred accordingly.
- In the event that another other large new generator applies for connection in advance of the new nuclear units (e.g. a Blyth-C 1500MW unit in 2015), the Infeed Change Date would be brought forward to 2015. Accordingly, a standard connection offer would be made in respect of Blyth-C recognising that the infrequent infeed loss risk is now 1800MW for the lifetime of Blyth-C and there would be no need for recourse to the 'variations to connection designs' clause.
- In the event of generator wishing to connect a generating unit, which poses a loss of power infeed risk in excess of 1320MW, before the Infeed Change Date, there would be a need for recourse to the 'variations to connection designs' clause. That is the generator would be responsible for the cost of additional response and reserve holding to enable the GBSO to maintain frequency to within statutory limits. An example would be the connection of an additional 300MW in 2012 at a point on the system where a 1200MW generator currently

connects to a dedicated double circuit spur. Since the connection is not in respect of a single generating unit in excess of 1320MW, the Infeed Change Date is not triggered. Accordingly, either a third transmission circuit is planned and constructed or the 'variations to connection designs' clause is used in which case the additional response and reserve would be met by the generator.

- In the event of generator wishing to connect a generating unit, which poses a loss of power infeed risk in excess of 1320MW but connection is not considered likely until after the Infeed Change Date, it is still possible that the GBSO would nevertheless require additional response. This possibility recognises the potential uncertainty relating to the new large units actually connecting on an expected Infeed Change Date. In view of this, it may be advisable to stipulate (perhaps in the appropriate Bilateral Agreement) that the generator would be responsible for any additional response and reserve required should the Infeed Change Date be delayed beyond current expectation. Wording may be along the lines of, "in the event that the Infeed Change Date, as defined in the SQSS, is later than the connection date of this application, then the Applicant is obliged to pay all extra Response and Reserve costs caused, as notified by National Grid".

The above circumstance is, however, deemed unlikely given that the lead time of such a small project is much less than the lead time of a nuclear station or large unit. Thus, by 2014, when receipt of such an application for 2018 may be expected, the timing of the Infeed Change Date should be relatively clear.

Drafting for GSR007 Implementation B

The Working Group does not recommend implementation style B for the reasons given under Section 9 of the main report. Nevertheless, it is mentioned here for completeness. Change proposals for style A3 and style B differ only in respect of the definition of Infeed Change Date. Accordingly, minimal changes would be needed to modify the wording of style A3 should this alternative be preferred.

Infeed Change Date: This date shall have the value 1st October 2017.

Re-Drafting of GB SQSS paragraph 2.6.3

The only other GB SQSS drafting change required relates to current paragraph 2.6.3 of the GB SQSS. The following amended version is recommended:

2.6.3: following a fault outage of any single generation circuit or single section of busbar or mesh corner, the loss of power infeed shall not exceed the infrequent infeed loss risk.

Drafting Commentary:

- The current wording of paragraph 2.6.3 in effect limits the connection of one or more generating units connected to a single busbar section to a total of no more than 1000MW. This means, for instance, that two separate 660MW units must connect to separate busbar sections. Clearly the connection of single units of 1650MW export capability (i.e. 1800MW loss of power infeed risk) would transgress this GB SQSS requirement.
- The effect of this change proposal will be to increase the limit under paragraph 2.6.3 to 1320MW immediately followed by a further increase to 1800MW from the Infeed Change Date. This would mean that two 660MW units could immediately connect to the same section of busbar resulting, amongst other things, in cost savings due to reduced numbers of busbars and busbar section circuit breakers.

After the Infeed Change Date, three 500MW units could connect to the same section of busbar, rather than only two.

ANNEX 4: COST-BENEFIT ANALYSES

The Cost-Benefit of Increasing the Normal and Infrequent Infeed Loss Risk on the GB Transmission System, from 1000-1320MW to 1600-1800MW

Summary

This annex presents a cost-benefit analysis of increasing the threshold limits of normal and infrequent infeed loss risks used in planning the GB transmission system. The main benefit is attributable to the carbon benefit due to connecting a fleet of six nuclear units each with a capacity in excess of 1320MW. Whilst further benefits are identified, the carbon benefit alone is well in excess of the dis-benefits expressed in terms of increased costs of system operation.

Introduction

GB SQSS Review Request GSR007 was raised by EDF Energy in February 2008, to review the normal and infrequent loss limits in the GB SQSS. This request is driven by the desire to connect nuclear units larger than 1320MW to the system, which pose a risk of loss of power infeeds of 1600MW or 1800MW. This paper discusses and quantifies the likely possible costs, in terms of response and reserve holding, of increasing the infeed loss limits and compares them with a number of wider benefits to the Power System.

Consequences of Increasing the Infeed Loss Risks

If the Infeed Loss Risks in the GB SQSS were increased, from 1000 / 1320MW to (say) 1320 / 1800MW, then there would be the following consequences to the Planning and Operation of the system.

Planning

- There is a clear potential for generating units, larger than previously experienced, to be connected to the GB transmission system in the future. Two of the three nuclear designs, submitted for Generic Design Assessment in July 2008, involve units with capacities in excess of 1320MW. In addition super-critical coal fired units, with capacities in excess of 1000MW, are also under consideration across Europe.
- Generation groups with a total capacity in excess of 1320MW could connect to the GB transmission system on one double-circuit spur.
- In general, fewer circuit breakers would be required in substation design. For example, three 500MW generators could be connected to a single section of busbar. Currently, such a design is not permitted as a busbar section fault would cause a loss of power infeed in excess of the current normal infeed loss limit (1000MW).
- Larger cables sizes could be used in the design of offshore connections. At present, it has been determined that the development of the GB SQSS to include offshore transmission systems should be subject to the same limitation on loss of power infeed as onshore (i.e. a normal and infrequent loss risk of 1000MW and 1320MW respectively). Accordingly, should the thresholds be increased the maximum loss of power infeed risk from a single cable connection may also exceed 1320MW.
- External interconnections between the GB transmission system and external systems (e.g. France or Norway) are covered by separate agreements which will normally be consistent with the GB SQSS. The GB SQSS may be specifically referenced in the relevant agreements and apply to the extent of that reference.

However, their connection to the GB transmission system is subject to the requirements of the GB SQSS.

With regard to imports across External Interconnections from External Systems, the loss of power infeed risk posed by the larger single-risk components, such as cables or bipoles, should be consistent with the requirements of the GB SQSS (e.g. in terms of permitted loss of power infeed) and the connections to the GB SQSS should be compliant with the generation connection criteria. An increase in the values of normal and infrequent loss risk will impact on both the relevant agreements and the level of investment in connection facilities.

- It is the perceived frequency of occurrence of the secured event which, in turn, determines the frequency of occurrence of a loss of power infeed. Accordingly, continued application of the current GB SQSS planning criteria for the design of generation connections will mean that there will be no change in the frequency of loss of power infeed regardless of the threshold level of normal and infrequent infeed loss risk adopted.

Certain design differences will however emerge since, for instance, with say a single 1800MW unit connected to a single busbar section it will not be permissible to connect a further generating unit, regardless of size, on an adjacent busbar section unless two section switches and two busbar coupler switches are installed between busbar sections.

- The criteria and methodologies of the GB SQSS are concerned with the GB transmission system and, other than in the case of generation circuits, do not reach into other systems. Should an event external to the GB transmission system (e.g. the loss of a nuclear reactor or an External Interconnection) lead to a loss of power infeed equal to the infrequent infeed loss risk at a frequency of occurrence inconsistent with the definition of infrequent infeed loss risk (e.g. more than say four times per year), additional measures would be required at the expense of the customer (e.g. generator) to enable NGET to achieve continued compliance with its statutory requirements.

Operation

- More primary and secondary response would be required, up to the new levels of normal and infrequent infeed Loss risk, at all times when at least one such risk was actually present and generating on the system.
- Possibly some extra upward reserve would be required, to cover the greater possibility of large losses of generation within operating timescales of four hours.
- If the total volume of nuclear generation increases on the system, there will be an increase in the costs of downward regulation at low demand periods.
- If more response is held, then the maximum volume of generation armed on system-to-generator intertrips could be increased, above the current limit of 1320MW.

All the consequences are quantified, and costed where possible, in the Cost-Benefit section below.

Assumptions

In order to assess the cost-benefit, the following high-level assumptions have been made:

Plant Background

A fleet of new nuclear units would not commission until at least 2015–2020. This paper makes a cost estimate for years generically in the third decade 2020–2030, against the following approximate plant mix (by production):

- Nuclear 15-25%
- Wind 10-40%
- Gas 25-40%
- Coal 10-30%
- Any other 0-15%

Electricity Demand

Whether demand on the GB system has fallen by 10% from current levels or risen by 20% does not have a material effect on the results of the cost benefit analysis. It is assumed that there is the equivalent of a 20% plant margin of installed generating capacity over peak demand, such that the current generation security of supply is maintained.

Current Market Arrangements

The current market arrangements remain for bulk electricity trading, and for response and reserve pricing are assumed to remain in place. Costs as charged out could of course radically change under different market arrangements, but the effect of these are not quantifiable at this stage.

Current Fuel and Energy Prices

Prices are based on the current 2008 cost levels, as expressed in current arrangements for response and reserve. Accordingly, it is assumed that the rate of inflation of fuel and energy prices, and the costs of generating capacity, is equal to the rate of inflation for the economy as a whole.

New Stations compliant with Grid Code

It is assumed that all new stations are compliant with the GB Grid Code. In particular, new nuclear units, although inflexible in that they do not shut down overnight, are compliant with the GB Grid Code in all other respects. In particular, the are assumed to comply with reactive requirements (normally no problem for nuclear), and they have the CC6.3.7 capability for 10% of high frequency response at full load.

Elements of the Cost-Benefit

This section considers the above planning and operational consequences and assesses associated cost and benefit as appropriate. The analysis is focussed on examining the effects of increasing the threshold levels of the loss of power infeed risk in the GB SQSS from the current normal and infrequent levels of 1000MW and 1320MW respectively to 1320MW and 1800MW. (The sensitivities relating to the 1320MW and 1800MW levels are addressed under item (b) of the section titled 'Alternate Scenarios', which is presented towards the end of this annex.

(a) Planning – Larger Generating Units

This gives the largest benefit. It is assumed that, unless the infeed loss risk levels are increased, the potential connection of a fleet of new nuclear units will not be able

to proceed. Accordingly, the cost-benefit analysis credited assumes a benefit derived from the entire new nuclear fleet.⁵

Such benefits could be very large. It could be argued that new nuclear will generate at a price cheaper than the likely marginal gas or coal generation price in the 2020s, and so give a benefit of reducing electricity prices. This benefit is treated as a qualitative benefit only and has not been quantified for inclusion in the analysis since the fuel price benefit (if any) accrues to the station developers, who offset it against the capital costs and the risks of building the stations.

It could also be argued that a new nuclear fleet gives national benefits on diversity of energy supply. Given the wide-scale nature of such benefits, it is not appropriate to quantify these arguments for use in the cost-benefit analysis.

A fleet of new nuclears will provide a carbon benefit, derived from the displacement of an equivalent capacity of conventional generation. DEFRA's medium-term advice for carbon benefit has been applied such that incremental generation in the medium-term can be assumed to be gas-sourced, at a carbon impact of 0.43 T_CO2/MWh.⁶ Government ambitions extend to a large fleet of new nuclear stations and it is appropriate to claim against a volume of six 1650MW nuclear units, on the basis that six such units are shown as 'Transmission-Contracted' in Table 3.16 of the 2008 Seven Year Statement:

$$\begin{aligned} \text{Generation of 9.9GW of nuclear at 85\% load factor} &= 9.9\text{GW} \times 0.85 \times 8760\text{hr} \\ &= 73.7 \text{ TWh}; \\ \text{Carbon Benefit} &= 73.7\text{TWh} \times 0.43 \text{ MT_CO}_2/\text{TWh} = 31.7 \text{ MT_CO}_2; \\ \text{Carbon Benefit, at current carbon price} &= 31.7 \times 25 \text{ £/T_CO}_2 = \text{£}790\text{m}. \end{aligned}$$

Carbon has been priced at the DEFRA shadow price of carbon of 25 £/T_CO2 (2007 price level), as advised for long-term policy and investment appraisals across Government. In November 2006 Stern stated that, over the medium term, carbon needs to be priced at around \$80/T_CO2 in order to meet a world-wide target of 60% carbon reductions by 2050. However, such high carbon prices are not considered in this analysis. It is also noted that the traded price for carbon, under the ETS across the years 2008 to 2012, has fallen from around 20 £/T_CO2 to around 10 £/T_CO2 over the second half of 2008. However, such a low price of Carbon is considered unsuitable for use in this medium-term appraisal.

Given the magnitude of this benefit due to the connection of new nuclear units, there is no need to assess any benefit against the more remote prospect of single conventional units in excess of 1320MW connecting to the system over the period 2020–2030.

(b) Planning –generation in excess of 1320MW connected to one double-circuit spur

If the infrequent infeed loss risk is increased to 1800MW, then a group of up to 1800MW of generation could be connected to the system on a single double-circuit

⁵ There is scope for mis-application of this principle. Where the cost benefit is based on a credit derived from the entire nuclear fleet, it may be argued that this would constitute double counting. However, provided the argument is only applied in isolation, then the basis of assessment of the GB SQSS proposal is valid and fair. There is no objective way to allocate a fraction, such that only 20% or 2% of the carbon benefit of the new nuclear power stations is taken into account.

⁶ Source: DEFRA "Guidelines for GHG Conversion Factors", Annex 3 long-term marginal, at: <http://www.defra.gov.uk/environment/business/envrpf/pdf/conversion-factors.pdf>

spur. The analysis considers one instance of such a group connecting to a 150km spur over the period 2020–2030⁷.

The relative saving here is that construction of a third transmission circuit is not required. On the basis of a generic cost of £0.5m per km for a single circuit, this represents a capital cost saving of £75m, which, when annuitised at 10%, represents an annual benefit of £7.5m pa.

(c) Planning – fewer circuit breakers in substation design

If the infrequent infeed loss risk level is increased to 1800MW, then (for example) three 500MW generators could now be connected to a single section of busbar. Under the current GB SQSS, such a design could cause a credible loss of 1500MW for a busbar fault, and would therefore require the installation of an extra circuit-breaker.

Against the prospect of 20GW of new conventional plant being connected by 2020, it is conservative to assume two instances where one circuit breaker could be saved. Moreover, in the TOs' programme of asset replacement by 2020, there might be three such instances where a circuit breaker could be saved. Each 400kV circuit breaker costs £1.0m, and so the capital saving is £5m, which, when annuitised at 10%, represents a benefit of £0.5m pa.

(d) Planning – larger cables in offshore connections

It has been determined that the offshore GB SQSS should be subject to the same limitation in terms of loss of power infeed risk as the onshore GB SQSS. For example, the maximum power infeed loss from a single offshore cable connection is 1320MW.⁸ There is the future possibility of a sizeable gain to be made by increasing this maximum size of offshore cable. However, current cable technology is such that it is not possible, at present, to quantify cable costs for such increased cable ratings.

(e) Planning – larger interconnectors

If the infrequent infeed loss risk is increased to 1800MW, then larger interconnectors to Europe could be entertained. At present, the likelihood does not seem particularly high, and the cost benefits are difficult to quantify. In view of this, no benefit is claimed in the analysis.

(f) Operation – more primary and secondary response

While operating the system, the GBSO holds primary and secondary response up to the levels of the normal and infrequent infeed loss risk, at all times when at least one such risk is actually present and generating on the system.⁹ This section determines: firstly, the extra volume of response theoretically required, as a function

⁷ The example referred to is the Downreay to Beaully route in the North of Scotland. There are a number of scenarios where more than 1320MW of wind and tidal generation may be developed on Caithness or Orkney by 2020.

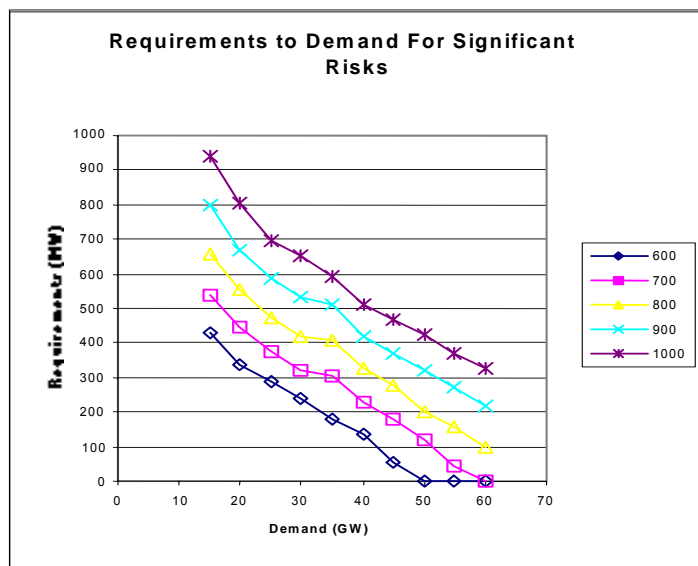
⁸ The Offshore Transmission Expert Group (OTEG) concluded in Spring 2007 that connection of a 1500MW windfarm on a single cable would be a maximum and that this would be consistent with the 1320MW infrequent infeed loss risk. This recognised that a 1500MW group of windfarms would rarely actually pose a risk greater than 1320MW. However, since the current regime intends single radial spurs for offshore connections, the Secretary of State determined that the size of windfarm should be the choice of the relevant developer and that the 1320MW infeed should apply at the commercial boundary between the offshore and onshore TO.

⁹ For an introduction to the requirements for frequency response of various types/characteristics, and for a description of the commercial arrangements around the procurement of frequency response, please refer to National Grid's web-site under balancing services:
<http://www.nationalgrid.com/uk/Electricity/Balancing/services/frequencyresponse>

of the extras risk level; secondly, the appropriate response policy to be applied; and thirdly to the cost the required response.

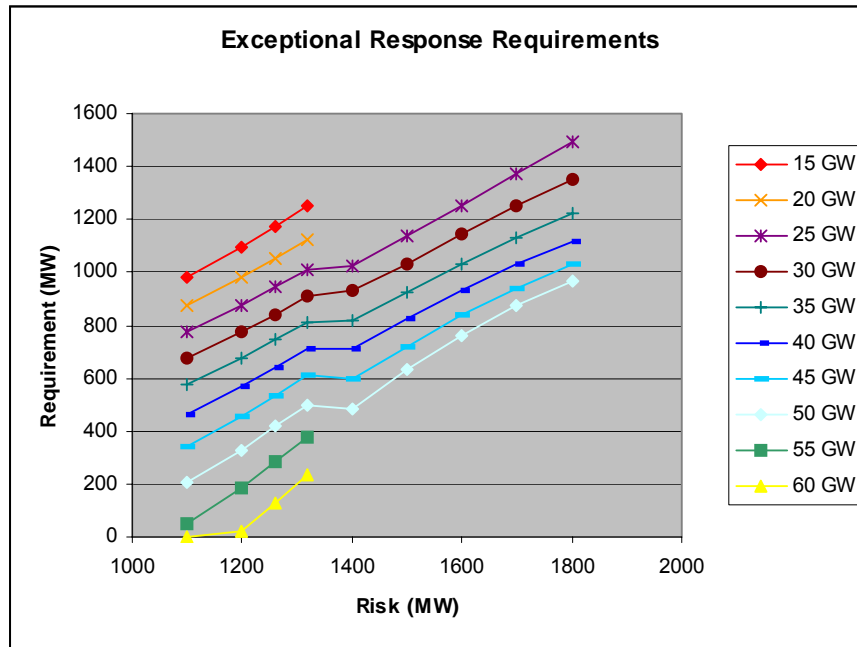
(1) Response Requirement, as a Function of Risk

National Grid last re-derived response requirements from first principles in 2003. This is a lengthy exercise, particularly for primary response, which requires simulation of the system in 0.1 second steps in response to an infeed loss, including dynamic simulation of all responsive machines and of the assumed response of demand to frequency. To review this work from first principles for the purpose of the present exercise is deemed unnecessary; rather, it is sufficient to extrapolate the results up to 1800MW risks. A re-derivation from first principles would be more appropriately carried out in some five to ten years time, closer to the point of need, by which time better data will be available on the dynamic characteristics of the GB transmission system with significant penetration of wind generation.



The simulation results, of primary response requirement as a function of demand and risk, are shown in the above Figure. Note that what is being termed a 'Significant Risk' is the 'Normal Risk' of the GB SQSS, and so the primary response is containing frequency to 49.5Hz, given a 50.0Hz starting frequency. Also note that the demand level plotted is E&W demand level, and so the X axis should be read in units 10% higher to correct to a GB demand (the chart was actually constructed on this basis, and then re-plotted).

The results are not particularly smooth, which is to be expected, since the simulation will have a different pattern of generation holding response at different demand levels. The important results are that the primary response requirement grows significantly for lower demand levels, and that it increases in reasonably constant steps at a given demand level as the risk increases.



The results for an 'Infrequent Infeed' loss risk, here termed the 'Exceptional' response requirements, are shown above. The step-change of the order 50MW from 1320MW to 1400MW risks is an artifice of the derivation, and should be ignored.¹⁰ The important result is that the increase in response requirement is linear with the increase in risk, for all demand levels, and averages out at 110MW of extra response per 100MW increase in risk level.¹¹

From the above results, the increase in primary response requirement is 110MW across all demand levels, for an increase of 100MW in Normal or Infrequent loss risk.

The equivalent result for secondary response relatively simple, in that the secondary response requirement is a linear function of demand and risk level. Hence each increase of 100MW in normal or infrequent loss risk (the recovery policy is the same for both) gives an increase of 100MW in secondary response requirement.

(2) Response Policy with 1800MW units

Given the delicate nature of the frequency obligations on the GBSO (as discussed above), it is not a straightforward matter to determine exactly how much extra response would be held, were there 1800MW nuclear units connected to the system. Two possible response policies are considered:

- A. By the time that there are more than six 1800MW risks on the system, irrespective of their actual trip rate, it is deemed that the actual trip of one is a normal event which should be covered to the normal infeed loss risk. Under this policy a full $(1800-1000) \times 110/100 = +880\text{MW}$ of extra primary response would need to be held.

¹⁰ The step-change arises because risks up to 1320MW were modelled on the basis of an infeed loss at Sizewell whereas risks beyond 1320MW were modelled on the basis of an infeed loss at Teesside (a switch fault at Teesside was the issue of concern at the time). A loss of some 1400MW at Teesside saves the system typically 50MW in power losses relative to the same loss at Sizewell.

¹¹ The technical studies of Annex 6 (which were conducted after this Cost-Benefit Analyses) argue that, in broad terms, it is sufficient to hold 480MW of response for the 480MW $(1800\text{MW} - 1320\text{MW} = 480\text{MW})$ increase in maximum risk rather than the $1.1 \times 480 = 528\text{MW}$ argued here. Accordingly, the Cost-Benefit Analysis is conservative in continuing to assume this fraction of 1.1.

- B. The actual full loss trip rate of the EPR reactor is claimed by the manufacturer to be once in nine years. Based on the scarcity of full 1800MW trips, it may be argued that the loss of an 1800MW unit constituted an infrequent infeed loss risk, in which case the extra response to be carried would be $(1800-1320) \times 110/100 = +528\text{MW}$.

At this stage, in advance of experience of any actual trip rate for new reactors, it is prudent to adopt a half : half assumption between these policies. Thus, on average $+(880 + 528)/2 = +704\text{MW}$ of extra primary response is assumed.

As noted above, secondary policy is relatively simple, and it is clear that an extra $1800-1320 = 480\text{MW}$ of secondary response is required to be held at all times. These figures assume that, by the time six new units are commissioned, at least one will be operating at all times posing an 1800MW risk. This assumption allows those rare occasions when the secondary response required is less than the level of the infrequent loss risk (as at present when less than 1320MW of secondary response is required) to be ignored when quantifying the increase in response from current levels.

(3) Cost of Extra Response

Before the introduction of CAP047¹² in November 2005, it would have been necessary to carefully consider the balance of primary and secondary response, in determining the on-cost of carrying +704MW of primary and +480MW of secondary at all times. However, since CAP047, response prices quoted for primary, secondary and high have become effectively meaningless. Most providers quote the majority of response price against high response.¹³

Table 4.1 presents the total balancing costs of response over the last two years:

Table 4.1: Cost of Response (£m)

Item	2006/7	2007/8	average	Notes
BM costs	36	32	34	This comprises the cost of pulling back gensets, to be able to hold Response
AS costs	124	126	125	This includes the costs of gensets holding mandatory response hourly, as priced under CAP047; also fees for Commercial Response from stations and demand-side
Total Response	160	158	159	

These costs are based on an average requirement of 800MW across the year. Thus an increase of 700MW in requirement will increase spend by an average of $\text{£}159\text{m} \times 700/800 = \text{£}140\text{m}$ (rounded).

(g) Operation – extra Upward Reserve

It might be thought that the presence of 1650MW units on the system would increase the possibility of large generation losses, and thus operating reserve requirements.

¹² CUSC Amendment Proposal CAP047 changed the pricing arrangements for mandatory frequency response provided from gensets in excess of 100MW. Previously, the price per hour of holding was determined on a cost-reflective basis between the Generator and National Grid. Following CAP047, the Generator is free to submit whatever commercial price he chooses, monthly.

¹³ The point here is that mandatory response can only be dispatched in the modes PH or PSH; if the entire price is on H, the operator has effectively no choice.

In fact, provided that the new units are fairly reliable base-load units, it is the case that they are not large enough, and do not fail often enough, to significantly affect the statistics of 4-hour ahead plant loss, which is the main driver of regulating reserve requirements.

However, the total requirement for operating reserve is the sum of the above regulating reserve, plus a requirement for frequency reserve. The frequency reserve ensures that there will be headroom on the gensets that generators will be instructed to hold as response. It should be noted that frequency reserve cannot be double-counted against regulating reserve. Regulating reserve is used to restore responsive capability within minutes of one infeed loss, in order that the system is then able to withstand a second infeed loss over the next few hours.

The average across the actual response held, is such that each MW of headroom (i.e. frequency reserve) can hold 0.55MW of response. Thus an increase of 704MW in response requirement will cause an increase of $704 \div 0.55 = +1300\text{MW}$ of frequency reserve requirement.

Table 4.2 presents the total balancing costs of operating reserve over the last two years:

Table 4.2: Cost of Operating Reserve (£m)

Item	2006/7	2007/8	average	Notes
BM costs	83	120	101	This comprises the cost of synchronising extra gensets, to hold Reserve
AS costs	70	64	67	This includes the fees for contracted standing reserve; and also warming costs paid to long-notice gensets
Total Operating Reserve	153	184	168	

These costs are incurred over a requirement that averages 3500MW over the year. Thus an increase of 1300MW in requirement will increase spend by an average of $\text{£}168\text{m} \times 1300/3500 = +\text{£}60\text{m}$ (rounded).

The extra part-loading of gensets to hold this extra frequency reserve is likely to cause some additional carbon emissions, because of the consequent inefficiency of operation. The cost of this extra carbon will be captured within the reserve cost quoted here, since providers of reserve are already exposed to the current price of carbon. For interest, the magnitude of the additional carbon is estimated in Appendix B to this annex.

(h) Operation – extra Downward Reserve

At times of low system demand overnight, the most onerous operational requirement is often the ability to tolerate sudden increases in generation or reductions in demand. It is necessary to have sufficient units capable of holding high frequency response, which are also capable of reducing instructed generation within the half-hour. Some £10m has been spent explicitly on such costs in recent years.

The addition of more nuclear generation on the system, unsuited to shut down over trough periods, will increase the costs of downward regulation. Investigation of a system with 6GW of nuclear replaced (the larger unit size is irrelevant for this cost), and with 10-20GW of wind generation installed, shows that only minor additional

costs, of order +£10m pa is incurred. This conclusion needs to be re-tested, against systems with a greater volume of wind generation.¹⁴

(i) Operation – increased Inter-trip volume

If more response is held, then the maximum volume of generation armed on system-to-generator intertrips could be increased above the current limit of 1320MW. However this constitutes an operational benefit only. Inter-trips are not regarded as a valid alternative to new transmission infrastructure.

The most obvious benefit here is in the case of generation in excess of 1320MW on a single double-circuit spur. Since the extra volume on inter-trip is merely solving the problem caused by permitting generation in excess of 1320MW on spurs in the first place, no benefit can be claimed. The planning benefit of connecting generation in excess of 1320MW is covered under (b) above.

However, it is reasonable to assume that there are two system boundaries in any year 2020-2030 that are as non-compliant as Cheviot is at present. On this basis, an extra volume of inter-trip will have a similar value as the Cheviot inter-trip, as developed commercially across 2006 and 2007. Our experience is that generators price commercial inter-trip services keenly against the BM alternative, and that a benefit of no more than £10m pa should be claimed.

(j) Overall Consideration of Operational Oncosts

The above arguments combine to represent an excessively prudent central estimate of the increased costs of holding the extra response, for the following reasons:

- In the early years, when only one to four new large units are commissioned, the trip rate will not be high, and so it is certain that the milder response policy B above can be followed. Hence, for the earlier years, the increased response volume will be 75% of that derived above; and
- In later years, when six (or more) new large units may be commissioned, the above arguments on volume hold. However, by then (i.e. in the late 2020s) current initiatives on smart meters and 'dynamic demand' may be assumed to reach some fruition, such that the average price of extra static response will be less, say 75%, of the current average price derived above.

In either event, there are reasonable arguments to assume 75% of the Response and Upward Reserve on-cost derived above. Accordingly, in the summaries presented below, a central estimate of 75% of the above values of +£140m and +£60m are used, namely: +£105m; and +£45m respectively.

Summary of Cost-Benefit

Table 4.3 provides a summary of the costs associated with the individual elements considered in the cost benefit analyses. The costs shown are in respect of a generic year 2020 – 2030.

¹⁴ We note that, strictly, this is an oncost of replacing the nuclear fleet, rather than an oncost of increasing the infeed loss risks. This modest cost is included in the cost-benefit analyses, since it represents the balancing oncost of the nuclear decision.

Table 4.3: Summary of Cost Benefit Analyses

Item	Annual Benefit (£m)	Annual Cost (£m)
Carbon benefit of larger nuclear units	790	
Greater than 1320MW of generation on double-circuit spur	7.5	
Fewer circuit breakers in substations	0.5	
Increase of 704MW in primary response held		105
Increase in operating reserve		45
Increase in downward regulation costs overnight		10
Increased volume on inter-trips	10	
TOTAL	810	160

Table 1 indicates that, in the central case of the cost benefit analyses, the benefits of increasing the threshold levels of the normal and infrequent infeed loss risk is some five times the associated cost.

Alternative Scenarios

The above has presented a central case of the cost-benefit of increasing the infeed loss risk. Estimating these effects 10-20 years out is subject to a large number of uncertainties, and a number of these are the subject of the following paragraphs.

(a) number of large nuclear units

The cost benefit analyses relate to a fleet of six 1650MW units, each of which pose an 1800MW loss of power infeed risk. The main costs of response and reserve are independent of the number of such units, since as soon as it is necessary to secure against one 1800MW risk on the system, the security provided satisfies the requirement for any number of 1800MW risks.

However, the main benefit of reduced carbon relates directly to the number of units assumed. Thus it can easily be seen, that if only two large units achieve connection to the system over 2020-2030, the cost-benefit breaks even. The benefit of two units (e.g. carbon benefit) is balanced by the increased cost of operating (e.g. increased response and reserve) the system. If only one unit commissions, then on the basis of the central case of this cost-benefit operational cost would outweigh the benefit. On the other hand, if more than six units commission, the cost-benefit is even more favourable.

(b) change in unit size

The above results of the cost benefit analyses are a function of different unit size. The carbon benefit is proportional to the absolute unit size whereas the on-cost of response and reserve is proportional to the excess of the risk level over 1320MW.

Thus for six 1500MW units, imposing a maximum risk of say 1600MW:

- Carbon benefit = $1500/1650 \times \text{£}790$ (from Table 4.3) = +£710m;
- Response and Reserve Oncost = $280/480 \times \text{£}150$ = -£90m;
- The totals read +£710m of benefits vs -£100m of costs.

The cost-benefit is more attractive for a smaller unit size.

Taking this argument to the limit, if the nuclear developers were to offer 1320MW units, much of the carbon benefit could be retained, and there would be no need to increase the infrequent infeed loss limit. This argument is addressed in Annex 7 of this report. In summary, the GB SQSS is subject to the requirement for the GBSO to

offer non-discriminatory terms for whatever generation technology chooses to connect to the GB transmission system.

(c) increased requirements for operating reserve

The cost benefit analyses assume current prices and costs for operating reserves. Given that the background by 2020–2030 will include 10%–40% of wind penetration, the requirements for operating reserves (on the basis of current operational standards) will have increased by some 50%–200% over current levels.

National Grid, has articulated in debates on wind generation scenarios over the last few years, does not believe this increase will cause a step-change in the price of operating reserves. The increase could in part be accommodated by re-building an OCGT capacity of 2600MW, as was inherited from the CEGB in 1990 (there is currently some 1200MW of OCGT capacity on the system). Current reserve prices are consistent with estimates of the capital and running costs of OCGTs. The entire increase in operating reserve could also be accommodated by running CCGTs part-loaded.

On the one hand, if scarcity of peaking plant leads to an increase in the prices for reserve capacity, then the cost estimates used in the cost benefit analyses would rise. On the other hand, if the greater requirement leads to successful development of a new technology, such as electricity storage or smart metering, then reserve costs may fall to slightly below the estimates used in the analyses.

(d) significant demand-side services

Were the electricity supply industry in Great Britain to pursue demand-side services such as smart metering and/or flexible demand control vigorously and successfully over the next decade, then the cost estimates on which the analyses have been based might reduce significantly. This area is too uncertain for any useful estimate of the price impact of such developments to be made at the present time, although a partial adoption of such arguments has been incorporated above.

(e) large AC interconnection with Europe

The estimates underlying the cost benefit analyses assume little more than the current level of interconnection with Europe and accordingly assume the current level of response and reserve services available to the GB transmission system from the European interconnection(s). If the interconnection with Europe were to be substantially increased (e.g. to over 6GW compared to the current 2GW capacity of the France–England link), and in particular if some of those links were AC ('alternating current'), then the costs of response and reserve could collapse to three quarters or even one half of their current level. However, there are no plans for such a substantial increase in link capacity.

The cost estimates of this paper might reduce by around 10%, on the construction of a flexible 1000–1500MW link with either Holland or Norway. Interconnection with Ireland would not reduce reserve or response costs since the Irish system is too small, in relative terms, to provide significant extra reserves to the GB transmission system.

Appendix A to Annex 4: Model of 4hour-ahead Plant Loss

One key driver of our 4hour-ahead requirement for operating reserve is the distribution of the 'plant loss'. That is the loss of generating capability due to power station failures and shortfalls in generation output, relative to that previously expected, over a period lasting 4hour. For winter peaks, the plant loss displays a skewed distribution with a mean of 600MW and a standard deviation of 450MW. The distribution is such that plant losses of 500MW which are deemed unlikely to recover, can occur but are unlikely. A plant loss of 2000MW can be expected to occur several times per year.

The following simple model provides an useful approximation to the distribution of plant loss. The statistics used provide a good approximation to the actual statistics. .

Assume that the GB system demand of 50GW is being supplied by 100 gensets each of 500MW, which each have a 0.01 probability of failing over the next 4 hours.

Then, by the binomial theorem,

- Mean plant loss:
= $500\text{MW} \times 100 \times 0.01 = 500\text{MW}$
- Standard Deviation of plant loss:
= $500\text{MW} \times \sqrt{\{ 100 \times 0.01 \times 0.99 \}} = 500\text{MW}$

Now add four 1500MW nuclear stations to this system, of unreliability 0.005 (since they are base load, this implies one failure every 800 hours of operation). 12 of our 100 X 500MW gensets will be displaced from operating on the system; increasing unreliability to 0.0105 since more peaking gensets are less reliable. This system has the following characteristics:

- Mean plant loss:
= $1500\text{MW} \times 4 \times 0.005 + 500\text{MW} \times 88 \times 0.0107$
= $30 + 470 = 500\text{MW}$
- Standard Deviation of plant loss:
= $\sqrt{\{ 1500^2 \times 4 \times 0.005 \times 0.995 + 500^2 \times 88 \times 0.0107 \times 0.9895 \}}$
= $\sqrt{\{ 45000 + 235000 \}} = 530\text{MW}$

The addition of the 4 large units has not changed the mean plant loss on the system (the numbers in the example were chosen to achieve this). The purpose is not to make the argument that the nuclears make the system more reliable (although such an argument could be made). The addition of the new nuclear stations has increased the standard deviation of plant loss by only 6%. This effect will increase the 4hour-ahead reserve requirement, but the effect will be diluted by the standard deviation of demand forecast, which is added into the equation and is of the same order.

Appendix B to Annex 4: Additional Carbon emissions from extra Reserve

For interest, this appendix estimates the extra carbon emissions, directly attributable to the extra holding of frequency reserve, as a consequence of increasing the infrequent Infeed risk from 1320 to 1800MW.

For coal-fired plant, the CEGB experience was that operating at part-load caused a 10% loss in station efficiency – this used to be expressed in the 'Willans line'. Thus five gensets operating at 400MW each consume 10% more fuel, and thus emit 10% more carbon, than four gensets operating at 500MW. Both operating regimes send out 2000MW of power, but the first holds 500MW of reserve. 1 MWh generated from coal emits 0.9 T_CO2. Accordingly, under this regime, 500MWh of reserve is emitting $10\% \times 2000\text{MWh} \times 0.9 = 180 \text{ T_CO}_2$ per hour.

Gas-fired plant can operate more efficiently at part-load, although there are efficiency losses from under-utilising a steam turbine. For simplicity, 10% loss in efficiency; is used since gas-fired plant is intrinsically less carbon-intensive, at 0.4 T_CO2 per MWh generated. Reserve held on gas-fired plant will only emit $0.4 / 0.9 \times 180 = 80 \text{ T_CO}_2$, again for 500MWh of reserve. On average, it is reasonable to assume that incremental reserve will be held half on coal and half on gas over the next 10-20years, and so the average carbon intensity of reserve will be $130 \div 500 = 0.26 \text{ T_CO}_2$ per MWh of reserve.

The central case cost benefit analysis is based on an increase of 1300MW of reserve held. So across a year, this will represent $1300\text{MW} \times 8760\text{hr} \times 0.26 = 3 \text{ MT_CO}_2$ of additional carbon.

ANNEX 5 – DISCRIMINATION ANALYSIS

Introduction

The impact of the proposed amendment of the GB SQSS was considered in the context of the requirement not to discriminate against market participants. The nature and concepts of “due” and “undue” discrimination were considered in the assessment of GSR007. The assessment debate then considered the application of these concepts to the proposed GB SQSS change.

Concepts of Due and Undue Discrimination

The issues of due and undue discrimination were considered in relation to the application of the criteria concerning the limits to loss of power infeed of the GB SQSS. Since there is no fully developed doctrine that defines what is of undue or due discrimination in the same way as might be found for price discrimination in competition law, it is more difficult to apply the concept of due or undue discrimination in practice. However, a review of the concept in Ofgem’s decision letters for CUSC modifications was useful. In addition, the Competition Commission, in their ruling of modification UNC 116, utilised the following definition:

“the legal test for unlawful discrimination is whether relevantly similar parties are being treated differently, or whether relevantly different parties are being treated in the same way”.

Ofgem argued in their open letter to the CUSC panel “*Efficient discharge of activities by the CUSC Amendment Panel*” 17th April 2007 that:

*“.[regarding] discrimination, as you will be aware, our consistent view has been (and remains) that the term requires (subject to what is said further below) **not only that like situations be treated alike, but equally that non-equivalent situations may be required to be treated differently.** This is typically referred to as “due discrimination”¹⁵.”*

*“It is also the case that no discrimination arises where like situations are treated differently provided that the difference in treatment can be **objectively justified** i.e. provided that the difference in treatment is pursuing a legitimate aim and is a **proportionate means of achieving that aim.** In reaching this interpretation we would rely not only on the normal meaning of the word and the intention of the provision in question, but also on the requirement not to “discriminate” in the relevant EC internal market directives and the meaning of that term as well elaborated by the jurisprudence of the European Court.”*

The application of this concept was considered for monopoly networks. In fact a neutral transmission operator and owner is a prerequisite for a fully functioning liberalised market. This point is well recognised in European legislation (e.g. Directive 2003/55 EC 2003/54 EC). Article 6 of Directive 2003/54 provides that:

*“For the construction of new generating capacity, Member States shall adopt an authorisation procedure, which shall be conducted in accordance with objective, transparent and *non-discriminatory criteria*” (emphasis added). Under the obligations in Article 9, each transmission system operator (TSO) must ensure “non-discrimination as between system users or classes of system users, particularly in favour of its related undertakings” (Article 9(e)), The regulatory authority for electricity in each Member State is responsible for ensuring non-*

¹⁵ <https://www.nationalgrid.com/NR/rdonlyres/2B5FDE28-2019-4B49-8488-6CB2F244363D/18170/OfgemResponsetoCUSCpanelFINAL.pdf>

discrimination, effective competition and the efficient functioning of the market."
(Article 23)

European Directives (1228/03) are directly applicable for any potential discrimination arising under GBSQSS.

Competition Policy and Price Discrimination

The concept of discrimination in the context of competition rules was also considered. The following points were noted by the Working Group:

- The prohibition of discrimination in the competition rules is an articulation of "the general principle of equality which is one of the fundamental principles of Community law. This principle requires that similar situations shall not be treated differently unless differentiation is objectively justified."¹⁶
- Article 82 of the EC Treaty (and the UK equivalent, Chapter II of the Competition Act 1998) contains a prohibition on the abuse of a dominant position, which can consist of discriminatory treatment. National Grid, as the monopoly owner of the sole electricity transmission system in England and Wales, may be considered to hold a dominant position on the market for the provision of electricity transmission services in that territory.¹⁷ The sole electricity transmission system might also be an essential facility, to which access must be granted on fair and reasonable terms.¹⁸
- Abuse of a dominant position includes "applying dissimilar conditions to equivalent transactions with other trading parties, thereby placing them at a competitive disadvantage" (Article 82(1)(c)). As stated by the ECJ, "subparagraph (c) of the second paragraph of Article [82] of the [EC Treaty] prohibits any discrimination on the part of an undertaking in a dominant position which consists in the application of dissimilar conditions to equivalent transactions with other trading parties, thereby placing them at a competitive disadvantage, irrespective of whether such discrimination is linked to nationality."¹⁹ (Case C-163/99, Portuguese Republic v Commission of the European Communities)
- Transactions between the transmission network operator and different types of generating companies (i.e. companies with different levels of generating capacity) should be seen as equivalent transactions.

¹⁶ Judgement in C-117-76 and C-16-77, Albert Ruckdeschel and Hansa-Lagerhaus Ströh v Hauptzollamt Hamburg-St. Annen ; Diamalt AG v Hauptzollamt Itzehoe, para 7

¹⁷ As held by the European Court of Justice ("ECJ") in *Corsica Ferries Italia Srl v Corpo dei Piloti del Porto di Genova*, C-18/93, ECR [1994] I-1783, "An undertaking which has a legal monopoly in a substantial part of the common market may be regarded as occupying a dominant position within the meaning of Article [82] of the Treaty". In Case IV/M1346 *EDF/London Electricity*, the European Commission took transmission, generation, distribution and supply of electricity to be separate product markets, "as they require different assets and resources, and the market structures and conditions of competition are different for each." (para 12)

¹⁸ In Guideline 414, *Assessment of Individual Agreements and Conduct* (1999), the OFT stated that "If a facility is considered to be essential, the Director General would expect competitors to have access at economically efficient prices in order to compete in a related market." (para. 7.5) The OFT stated in these Guidelines that potential examples of essential facilities included "utility distribution networks (for example, electricity wires, water and gas pipelines)" (para 7.3)

¹⁹ Case C-163/99, *Portuguese Republic v Commission of the European Communities*, ECR [2001] I-02613), para 46

Application to GB SQSS

The Working Group acknowledged and noted the concept of due and undue discrimination and the examples/precedents which have been set regarding this issue. The applicability of the concept with respect GSR007 was assessed by the Working Group.

It is first important to understanding the rationale and facts behind the standard and the context matters in which it resides. The current regulations allow connection up to 1000MW for a single unit and after that a “non compliant” charging regime is instigated. The existing regime could be viewed as discriminatory if the Transmission System were technically able to accommodate the generation on the system.

The Working Group noted and debated the following points:

- The avoidance of discrimination by Transmission Owners and System Operators is a priority for energy regulators. The fair treatment of generation technologies is a prerequisite for a fully liberalised market.
- The standard has historically been linked to changes in generation technology. If this link is broken the standard becomes both arbitrary and discriminatory.
- Furthermore consumers, suppliers and generators do not benefit innovations in generation technology if the current standard remains.
- GB SQSS has the scope to reduce competition in generation if generators are unable to connect the equipment of their choice.

The Working Group noted that by not changing the infeed loss limits, to reflect the technology advancements in power stations, it may act against the objective of promoting competition in the generation market. In this regard it may be that the rules could be discriminatory in this respect.

Conclusion

The issue of due versus undue discrimination can only be determined against the findings of the technical analysis. As has already been stated the “principle requires that similar situations shall not be treated differently unless differentiation is objectively justified²⁰”. Without such ‘objective justification’, it appears that different treatment of generators using different technologies and sizes of generating units cannot be justified and could be discriminatory.

²⁰ CF note 3

ANNEX 6 – TECHNICAL STUDIES

Impact of 1800MW loss on system frequency issues

Background

National Grid has statutory obligations to maintain the frequency of the GB transmission system within a defined range around 50Hz. Maintenance of this frequency requires consistent matching of the total generation and load connected to the system. Any unbalance causes a frequency change.

Continual small changes in frequency occur during normal system operation as demand and generation vary throughout the day. These changes are managed by small changes in the outputs of generators, determined by their governors, and by the nature of the system load, which varies with frequency to reduce the change.

Large step changes in either the level of demand or generation will cause large imbalances and consequently large frequency changes. Without significant response from either or both the demand and generation to remove the imbalance, these large losses could result in frequency changes sufficient to cause further plant loss, defensive load shedding, and possibly collapse of the power system.

The amount of demand and generation response required to ensure system security depends on the size of the loss relative to total system demand (or generation). National Grid's obligations are to ensure system security for losses considered credible for the GB system. At present the largest credible loss is 1320 MW (the 'infrequent loss'). The introduction of new generating plant in the future may mean that the largest credible loss will increase to 1800 MW. This will have implications for the level of response required following such a loss. This note discusses the frequency related issues associated with increasing the largest credible generation loss to 1800 MW.

Provision of Response

Following the loss of a generating unit, response is provided from five sources, namely: the energy stored in the rotating masses of the generators; the energy stored in the rotating masses in the loads; the frequency dependency of the load; increased mechanical power supplied to remaining generators; and sometimes tripping of demand.

Generating unit and load rotating masses

Any rotating mass has energy stored in it dependent on the inertia of the mass and the speed of rotation. Both generating units and motors contain rotating masses and therefore stored energy. Following the loss of a generating unit there is an imbalance between the mechanical energy being supplied to generator turbines and the electrical energy being consumed by the load, which at all times equals the electrical energy being supplied to the system. The difference between the mechanical energy being supplied to the generating units and the electrical energy being supplied to the system during the transient phase is made up from the stored energy in the rotating masses. As stored energy is removed the speed of rotation of the machines, and therefore the system frequency, must reduce to reflect the new level of stored energy. The speed of rotation will only remain constant when the mechanical power supplied to the turbines equals the electrical load consumed.

Frequency dependency of load

The energy consumed by loads connected to the system varies with frequency in a manner that reduces the change. That is, for a falling frequency the load reduces.

Increased mechanical power to generators

The Grid Code requires most generating units to be capable of providing a response to a frequency change. This is achieved by governor action. The energy delivered to the turbine is increased for a reduction in frequency (and vice versa). In order to be able to provide response generating units are operated at reduced output. The provision of this response begins shortly after (typically between ½ and 2 seconds) the generation loss and increases with time to a level that is sustained for several minutes. The level to which units are part loaded, the number of part loaded units, and the profile of response provided is determined by commercial contracts and technology type.

Tripping of demand

The generation / demand imbalance can also be reduced by tripping demand from the system. A number of large loads have been contracted to trip should the frequency fall to specified threshold levels. Demand tripping has the advantage when compared with increasing generation output in arresting frequency falls that it provides a step change, giving its full benefit instantaneously, thereby reducing the energy required from the rotating masses and the consequent fall in speed.

Response is normally provided by all of the above. The initial rate of change of frequency (ROCOF) is dependent on the energy supplied from rotating masses and the frequency dependence of the load. Without contracted demand tripping or generation response the frequency will not stabilise before load shedding by the defensive low frequency demand disconnection (LFDD) scheme and, possibly, further generation tripping and collapse of the system. Response from generation and demand tripping will determine the minimum frequency reached and restore it to a level within the statutory operating range.

The level of demand at the time of a generation loss will affect both the level of load reduction with frequency and the energy stored in rotating masses. Different levels of generation response and demand tripping are therefore required to limit and restore the frequency to within statutory limits for different demand levels for a given loss. In general, more is needed as the demand reduces.

Impact of 1800 MW loss

A loss of 1800 MW will have two main impacts when compared with a 1320 MW loss: the ROCOF will be higher and the total response requirement will be greater. To assess these issues studies have been carried out.

Studies

The studies have applied generation trips of 1320MW and 1800MW to the GB transmission system. From these studies the ROCOF values have been obtained and the response requirements to limit the frequency fall to 49.2 Hz and return it to 49.5 Hz have been determined.

Three demand scenarios have been considered: 24GW, 45GW and 61GW. The scenarios have been based on a future system with high levels of wind and nuclear generation, as detailed in Table 6.1.

Table 6.1: Scenario Plant Mixes

Scenario	Wind (GW)	Nuclear (GW)	Thermal (GW)
24 GW	12	8	4
45 GW	21	9	15
61 GW	21	9	31

The plant mixes studied raise issues in addition to the impact of an 1800 MW loss. These include:

- the inertia of wind generators – it is anticipated that future wind turbines will be connected to the system by dc converters. Without supplementary controls, these converters will decouple the generator from the system frequency and mean that no energy is supplied from the rotating mass. This will affect the study results. Wind turbines have been modelled with no inertia in these studies.
- the provision of response from generators – at present response is mainly provided by thermal plant. In the scenarios considered it may not be possible to provide the required response from the thermal plant in the base study. Provision from wind and nuclear, or the displacement of these, may be required.

Both of these issues are outside the scope of this analysis. By finding the difference in the consequences of a 1320 MW trip and an 1800 MW trip, the effect of these factors has been minimised.

The studies have used a simple equivalent network in which the generation types have been lumped into separate, equivalent single generators. These generators are modelled dynamically, with typical governor characteristics. The network is shown in Figure 1.

The demand has been included as a single load, with a frequency dependence of 2% per Hz. The demand does not contain dynamic models of the load and therefore does not provide energy from the rotating mass within the load. This response is accounted for by modifying the inertia of the generating units, as described in Appendix 6.1.

The model used, including the effect of the load inertia, has been validated against system incidents where generation has been lost causing a large frequency fall.

Results

The difference between the two losses is 480 MW. The results of the studies show that the additional response requirement between the studies at the point of minimum frequency and during the sustained post trip steady state is 480 MW, within a small range (450 MW to 510 MW).

It is expected that the additional response requirements will be consistent with the difference in loss when attempting to obtain the same frequency performance. For a given frequency the load will be the same, regardless of loss. For a frequency that is neither rising nor falling there is no energy supplied from the rotating masses and so the mechanical input power must match the electrical load. This is the case at the minimum frequency point and the post fault sustained frequency. Consequently at these frequencies the response difference should exactly match the difference between the trip sizes. The range of values seen in the studies arises from comparing results when the obtained frequencies are not identical.

The studies have also assessed the ROCOF values resulting from the two losses. These are shown in Figure 6.2. The absolute values obtained are significantly

dependent on the inertia of the machines and are outside the scope of this working group. However, two scenarios have been studied for the 24GW load to give an indication of the sensitivity. In one scenario the required response to maintain the system frequency within statutory limits has been obtained from thermal plant, and wind generation has been displaced to include sufficient responsive plant in the study. The displacement of wind (assumed to have no inertia) reduces the ROCOF values. In the second scenario the generation pattern of Table 6.1 has been maintained, requiring response to be provided by wind and/ or nuclear generation. This has resulted in higher ROCOF values. This scenario is labelled “variation” in Figure 6.2. This demonstrates that the way in which response is contracted for will influence the post trip ROCOF. This issue is being considered by a separate industry working group. The relative values indicate that the ROCOF is up to 40% higher for the larger loss.

Conclusions

The analysis shows that increasing the maximum system loss from 1320 MW to 1800 MW will increase the required post trip response by 480 MW, the difference in trip size. The ROCOF seen following an 1800MW trip may be of the order of 40% higher than for a 1320 MW trip. The ROCOF will be influenced by the generation mix, which in turn is influenced by reserve holding contracts.

It is not expected that the additional reserve holding requirement will prevent secure operation of the power system. Issues associated with ROCOF are being considered in an industry working group.

Figure 6.1 – Equivalent network used in studies

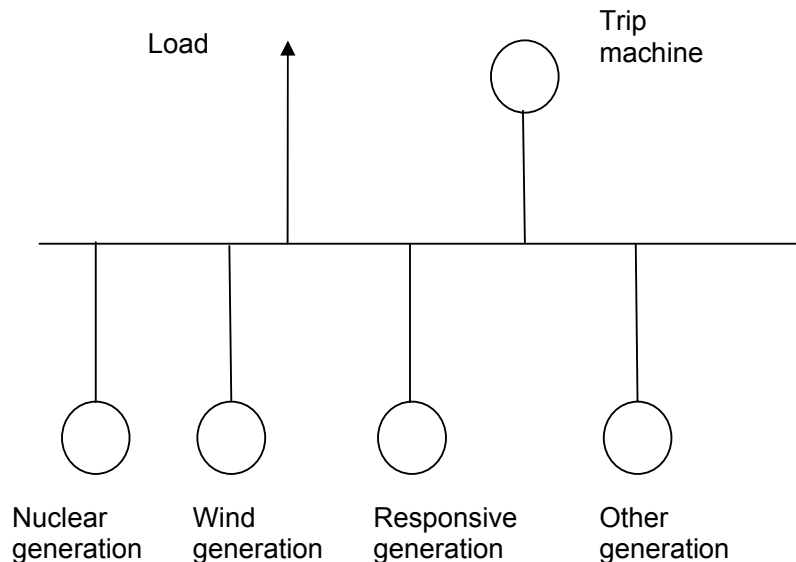
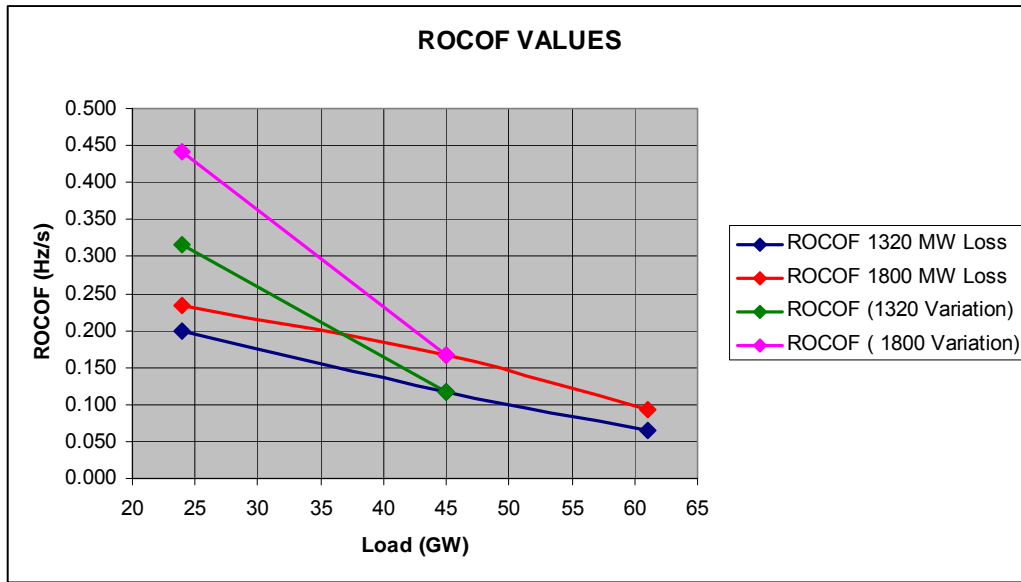


Figure 6.2 – Comparison of ROCOF values



Appendix 6.1 – Inclusion of load inertia

Whenever there is an imbalance between the mechanical energy supplied to generating units and the electrical demand of the total system the difference is made up from energy stored in rotating masses of machines, both generators and motors. The energy stored in these masses and the rate at which their rotation slows as energy is released depends on their inertia.

The inertia of generating units is known from Grid Code data submissions and can be explicitly modelled in analysis work. In the analysis described in this report typical inertias for the generating types modelled have been used. Wind generators have been considered with no inertia due to the anticipated nature of their connection via dc converters.

The inertia of the system load is unknown. Separate analysis of a system incident involving a large frequency drop for which measured frequency and generation response information is available has been undertaken. By including the measured response of generators in the analysis the amount of additional energy that must have been supplied by the load during the incident to produce the measured system frequency has been calculated.

In the studies of this report the energy stored in the different loads considered has been scaled from the known level described above by the ratio of the study demand to the demand level of the system incident. This stored energy has been included in the studies by increasing the inertia of the system generators so that they contain the total stored system energy.

Appendix 6.2 – Simplified analysis

A simplified response requirement analysis can be carried out if the dynamics of providing that response are ignored. That is, it is assumed that the response is available in time to ensure that the frequency does not change by more than 0.5Hz for a Normal Infeed Loss, or by more than 0.8Hz for an Infrequent Infeed Loss, and that the frequency returns to above 49.5Hz within 60s.

As discussed in the main part of this annex, the system load is frequency dependent. If D is the frequency sensitivity of the load in p.u./Hz, the system load *after* a frequency deviation of Δf Hz, is given by:

$$P'_L = P_L(1 + D\Delta f), \quad (6.2.1)$$

where P_L is the system demand before the change in frequency. To ensure that a particular frequency limit is not exceeded after an infeed loss incident, the total pre-incident generation (P_G), less the infeed loss (P_{LOSS}), plus the response (P_R) has to at least equal the post-event demand, P'_L :

$$P_G - P_{LOSS} + P_R = P'_L \quad (6.2.2)$$

or,

$$P_R = P'_L - P_G + P_{LOSS} \quad (6.2.3)$$

It is reasonable to assume that, before the infeed loss occurred, generation exactly matched demand ($P_G = P_L$). Therefore, eq. 6.2.3 can be simplified to:

$$P_R = P_L D \Delta f + P_{LOSS} \quad (6.2.4)$$

Thus, eq. 6.2.4 can be used to determine the response requirement for a given system demand, infeed loss and maximum frequency deviation. Such results are given in the table below (using a load frequency sensitivity of 2%/Hz, or $D = 0.02$ p.u./Hz).

The second and third columns show how much response is required to ensure that the system frequency does not fall by more than 0.8Hz for infrequent infeed losses of 1800MW and 1320MW respectively. I.e. this is the response that will ensure that the frequency will not fall below 49.2Hz (starting from 50Hz). Given that enough response is held to cope with an infrequent infeed loss of 1800MW, how large could a frequent infeed loss be without exceeding the 0.5Hz frequency deviation limit? The solution, for each demand level, is shown in the fourth column.

System Demand, P_L (GW)	Response required (P_R in MW) to ensure that frequency deviation does not exceed 0.8Hz		P_{LOSS} to ensure $\Delta f = -0.5$ Hz, assuming response held for $P_{LOSS} = 1800$ MW
	$P_{LOSS} = 1800$ MW	$P_{LOSS} = 1320$ MW	
22	1448	968	1668
30	1320	840	1620
40	1160	680	1560
50	1000	520	1500
60	840	360	1440
80	520	40	1320

ANNEX 7 – ISSUES OUTSIDE THE SCOPE OF GB SQSS

During the course of this review a number of issues have been identified which fall outside the formal scope of the GB SQSS. These issues do not warrant detailed discussion within the main text of this report but they are deemed worthy of recording in this annex for completeness.

This Annex is drafted in 'Question and Answer' format.

Q1. Why can't large gensets connect with turbines and units less than 1000MW?

A1. Potentially, there are a number of GB Grid Code compliance issues relating to generating units greater than 1000MW. These issues, which are currently being addressed, concern, for example, the current reactive capability requirement of 0.85 lagging (Grid Code CC6.3.6 refers) and a short circuit ratio requirement of 0.5 (Grid Code CC6.3.2 refers). However, such GB Grid Code issues are outside the scope of the GB SQSS and rather fall within the scope of GB Grid Code governance.

This question is in fact irrelevant to this review. The driver of the operational level of response is the boiler or reactor size, as explained in Annex 6. Even if a 1700MW unit were connected by 2 x 850MW turbines, the Operator would need to hold the extra Response, and all the issues of this report arise.

Q2. Why can't the Generators limit themselves to Boilers and Reactors less than 1320MW?

A2. This is very relevant to the Discrimination issue. If no-one had intended to connect boilers or reactors greater than 1320MW, then this review would not be required. A cost-benefit analysis of the economies of scale achieved by boilers or reactors greater than 1320MW versus the costs of extra response may prove useful. In conducting the present review, the Working Group has neither sought nor been offered any such estimate of capital or operational savings.

However, such a cost-benefit analysis would run counter to competition in generation. Generators internalise all the capital and operating costs, and reflect them into their offered prices for electrical energy into the market.

It is reasonable to assume that such costs would justify any the extra costs for response. This leaves only the discrimination issue of whether it would be discriminatory to leave boilers and reactors greater than 1320MW exposed to the the additional response on-costs.

Q3. Is there a cost-benefit for the extra Response?

A3. This report neither considers nor proposes any change to the level of security or quality of supply provided by the current GB SQSS including the operational criteria of Section 5 of the GB SQSS. A simple cost-benefit justification for this is outlined below:

On the assumption that:

- A fleet of six new large units trip, and impose an infeed loss of 1320-1800MW once per six years each; once per year across the six;
- A few transmission risks of 1320-1800MW evolve, and impose a further such loss event once every four years;

- Without the extra response, the system loses 10% (two stages of LF relay) x 40GW (average demand) x 2 hours (restoration time); and
- This lost load is priced at 33000 £/MWh. This is the price that Ofgem have set in the 'Transmission Network Reliability Incentive' under which National Grid has been exposed to a cost of network unreliability since 2005 and thus forms a current measure of Ofgem's Value of Lost Load (at least as applicable to network events).

Then it follows that:

- The cost of avoiding the event = cost of extra response = £200m pa (as per Annex 3);
- The probability of event = 1.25 events pa;
- The benefit of lost load avoided per event = 4GW x 2hr x 33,000 £/MWh = £260m; and
- the expectation of lost load avoided = 1.25 x £260m = £330m pa.

The cost of the extra response is less than the expectation of lost load; hence the extra response holding is justified.

Q4. What is the Impact of units in excess of 1320MW on Security of Supply?

A4. The following paragraphs consider how the connection of one or more 1800MW units to the system affects overall system security of supply, i.e. the ability to meet demand at winter peak. It is important to note that this aspect of system security is considered to be outside the scope of the GB SQSS, because the transmission licensees (or indeed the system operator) have no control over either the total generation capacity connected to the network (i.e. the plant margin), nor the availability of individual generation units (these are controlled by the generation market). Nevertheless, the security of supply implications of displacing smaller generation units with 1800MW units, are considered in the following high-level analysis. The following assumptions were made:

- All generators have unit sizes of 300MW, or 1800MW in the case of new, large units.
- The system ACS peak demand is 60GW.
- In nine winters per century, there will not be enough generation available to fully meet the ACS peak demand, i.e. the Loss of Load Probability (LOLP) is 9%.
- Unit availability is fixed at 86.15% for all generators (see discussion below).
- Wind generation is ignored. It is acknowledged that a high penetration of wind generation will affect the results of this investigation, however, the inclusion of wind would complicate the analysis considerably. Also, the treatment of wind is being considered as part of the fundamental SQSS review currently in progress.
- The limitations of transmission and distribution systems are ignored.
- All generation units are statistically independent.

In the simplified analysis presented here, the base case is a system with 240 × 300MW units, giving 72GW of installed generation capacity. This gives a plant margin of exactly 20%, which is usually assumed in planning timescales. Therefore, in the base case, LOLP is the probability that 41 or more of the 240 units will not be

available at winter peak. If X is the number of unavailable units, then, using the binomial distribution:

$$LOLP = P(X \geq 41) = \sum_{x=41}^{240} b(x; n = 240, p = 0.8615) = 0.09$$

Note that the 86.15% reliability figure was specifically selected to satisfy the above relationship, i.e. that a 20% plant margin equates to LOLP = 9%.

This type of simplified analysis is clearly not an accurate representation of the system and its reliability. However, the intention is to show, in broad terms, the impact of connecting large units to the system without complicating the mathematics unnecessarily²¹.

The impact of maintaining a constant plant margin, but introducing an increasing number of 1800MW units, was investigated (i.e. each time a new 1800MW is added, $1800 \div 300 = 6$ of the 300MW units are displaced). The results are shown in figure Q4.1. The initial jump in LOLP may seem excessive, but it has to be remembered that the six 300MW units that have been displaced provide a much higher combined output power availability than a single 1800MW unit with the same availability (per unit).

In planning studies, a plant margin of 20% is usually assumed. In practice, the transmission planner has no control over the plant margin – this is determined by the market and changes as generation plant opens and closes. The impact of connecting a number of 1800MW units on the plant margin is considered in the following paragraphs. The question is: How must the plant margin change to maintain constant LOLP as large units are connected?

Figure Q4.2 shows how LOLP changes as the plant margin is adjusted for the base case and for systems with 1, 3 or 6×1800 MW units connected. The plant margin was increased by adding additional 300MW units (i.e. one 1800MW unit effectively displaces less than six 300MW units). Based on these results, figure Q4.3 shows the plant margin as a function of the number of connected 1800MW units, required to maintain constant LOLP. It can be seen that the connection of the first 1800MW unit requires a jump in the plant margin to 21%, followed by an increase of approximately 0.23% for each additional large unit.

²¹ Note that the unit sizes of 300MW and 1800MW were also chosen for mathematical convenience, as 1800 is an integer multiple of 300.

Figure Q4.1: Increase in LOLP as number of 1800MW units increased (assuming constant 20% plant margin).

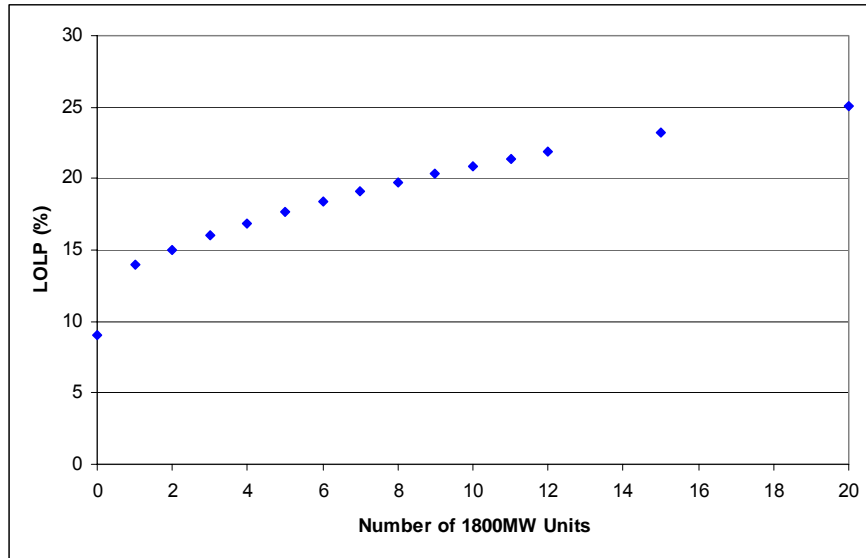


Figure Q4.2. LOLP as a function of plant margin and number of 1800MW units (n).

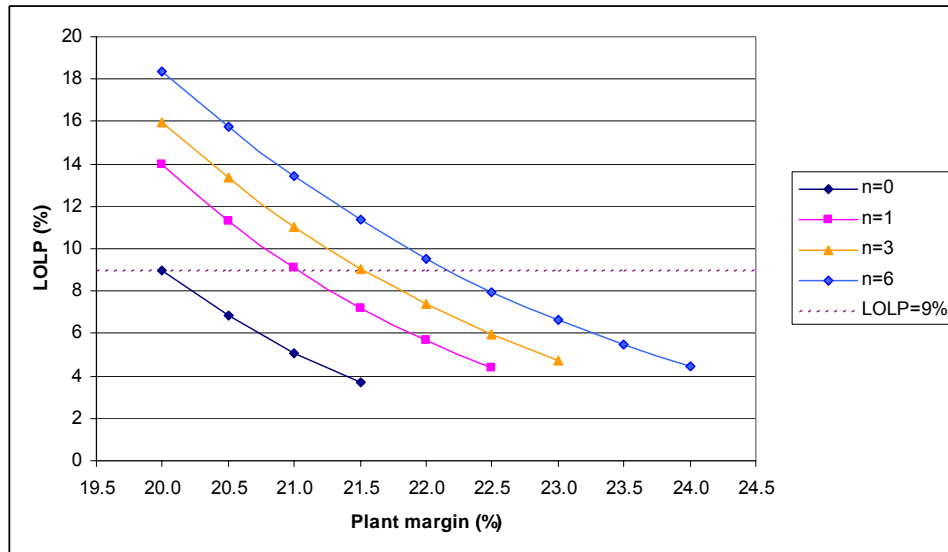
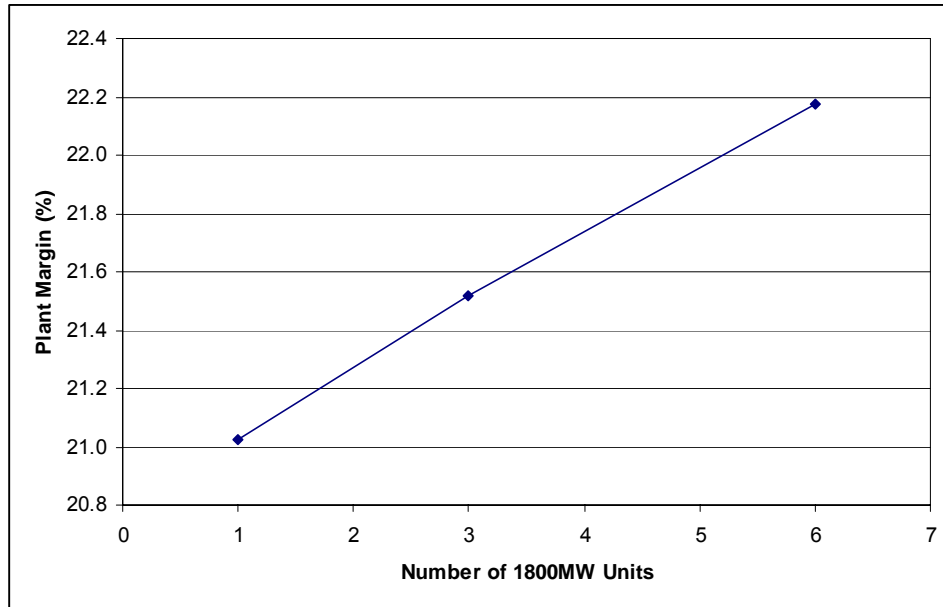
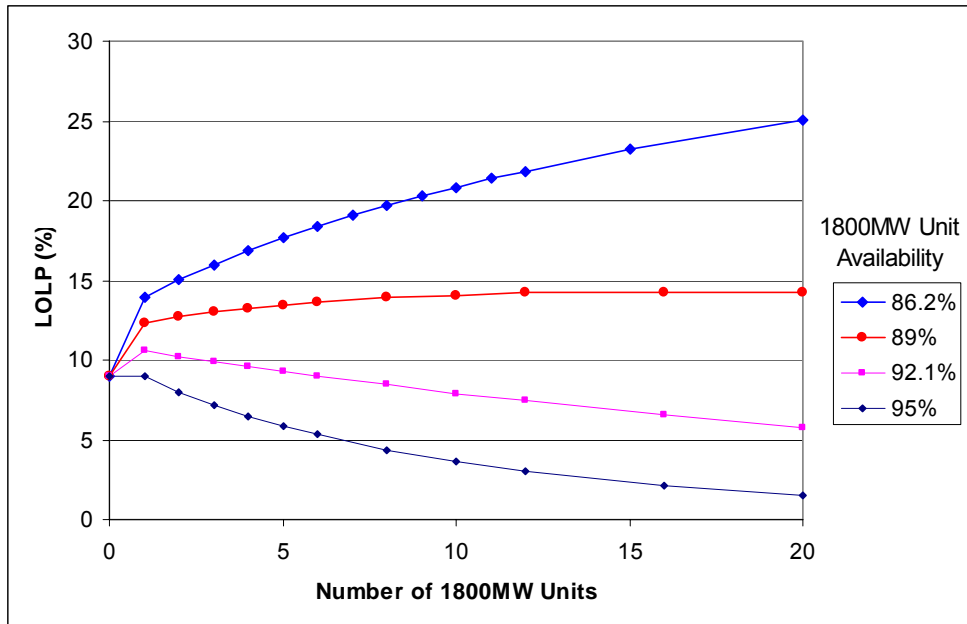


Figure Q4.3: Plant margin required for constant LOLP=9% as number of 1800MW units is increased.



Based on these results, it could be concluded that an increased plant margin is required to maintain security of supply as the number of 1800MW units on the network is increased. However, the availability of such large units at winter peak may well be much higher than the 86% assumed in the analysis. In fact, if a 95% availability is assumed for the 1800MW units, LOLP will reduce as the number of 1800MW units increases, dropping to just above 5% for $n=6$. A 92% availability for the 1800MW units leads to an initial increase in LOLP, but this falls back to the initial 9% when $6 \times 1800\text{MW}$ units are connected to the system. A comparison of LOLP values for different 1800MW unit availabilities is shown in figure Q4.4 (note that the availability of the 'standard' 300MW units was kept constant throughout).

Figure Q4.4: Increase in LOLP as number of 1800MW units increased for different availabilities (assuming constant 20% plant margin).



Q5. What is the impact on the Low Frequency Demand Disconnection (LFDD) scheme?

A5. The LFDD scheme has been designed as a means of limiting the consequences of major system frequency incidents. The first stage of the LFDD scheme is set to operate at 48.8Hz, which is 0.4Hz below the minimum frequency that could be reached during a secured event (such as the loss of a 1320MW or 1800MW infeed). The scheme is designed to cope with a wide range of infeed losses (such as the near-simultaneous loss of several generation units) and system splits (which could leave one part of the system with a very large generation deficit). I.e. the LFDD scheme is designed to cope with generation deficits far in excess of the infeed losses against which the system is secured operationally and is therefore not affected by an increase in the normal or infrequent infeed loss limits.