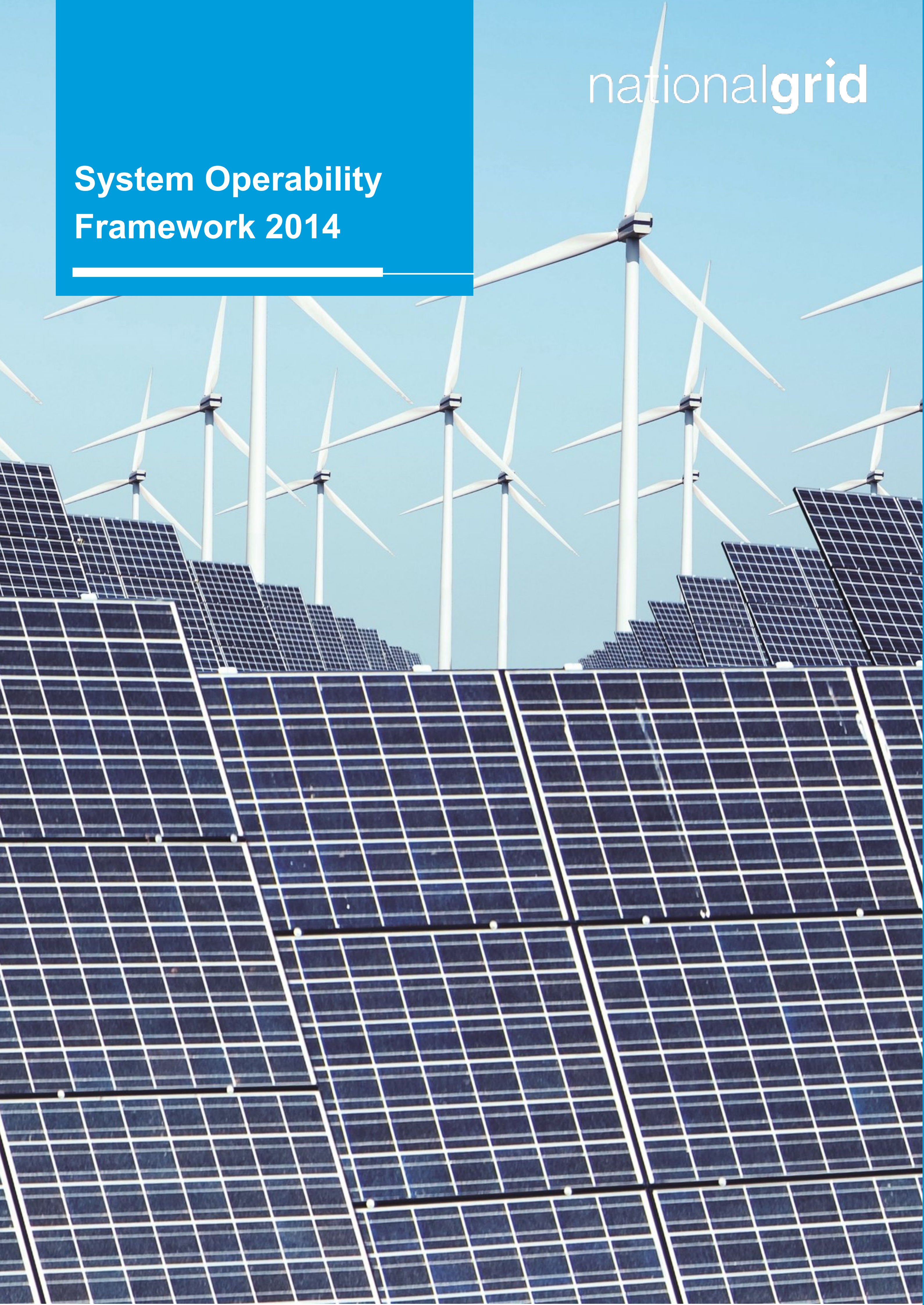
System Operability Framework 2014



Welcome to the 2014 edition of the GB System Operability Framework (SOF). This framework has been developed to provide a holistic view of the long term system operation aspects, as well as to provide a greater clarity on the impact the UK Future Energy Scenarios may have on GB electricity transmission system operability.

Contents

Executive Summary

The System Operability Framework (SOF) aims to outline how future system operability is expected to change in response to the developments described in the UK Future Energy Scenarios (FES). It aims to help existing and future customers to identify new and enhanced service opportunities on both the onshore and the offshore transmission systems.

Figure 1 System Operability Framework Stakeholders

2014 marks the first year that National Grid has published its System Operability Framework (SOF). The SOF draws upon both the real-time experience of the System Operator and the outlook of the Future Electricity Scenarios[1] (FES) for the period out to 2035 as recently published.

System operability is the ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably. By combining knowledge and experience with detailed system analysis, it is possible to extrapolate the current experience of operating the network out into these future years, across multiple future scenarios to identify common themes where factors influencing the operability of the network are subject to particular change, and to evaluate different approaches to mitigate or adapt to such changes where they occur. This executive summary looks to set the backdrop to the more detailed analysis that follows, and highlight those key areas of particular interest and activity going forward. It is our intention that the SOF will continue to support future FES and Electricity Ten Year Statement[2] (ETYS) documents in future years, to support a common understanding across the industry of the factors driving network innovation, and the context under which technical codes established in Europe will be implemented in a National UK context.

Background

FES is annually produced by National Grid with the aim to project the future GB energy landscape in terms of power generation mix and demand. National Grid uses FES to identify extra transmission capacity required across the network to meet future needs. The results of this process are published annually in the ETYS that also includes a high level overview of the impact of FES on system operation. Feedback on both FES and ETYS can be provided through annual consultation processes.

The SOF has been designed to study the scenarios described in FES on system operability annually, in a detailed and systematic way that takes into account current system operation experience and applies this and the FES predictions to future operation. It highlights the key system operability variances under each of the scenarios set out in FES and provides an assurance that the risks associated with system operability are identified. This ensures that the necessary mitigating measures can be evaluated early enough to allow for full economic assessment and timely implementation of solutions.

The time frame within which system operability changes occur is dependent on the present situation in relation to all of the operability areas, the power generation mix, i.e. if the extent of non-synchronous generation (NSG) penetration increases, and the changes in the behaviour of demand and generation sources. These then define when system operability challenges occur and the rate at which their incidence increases over time.

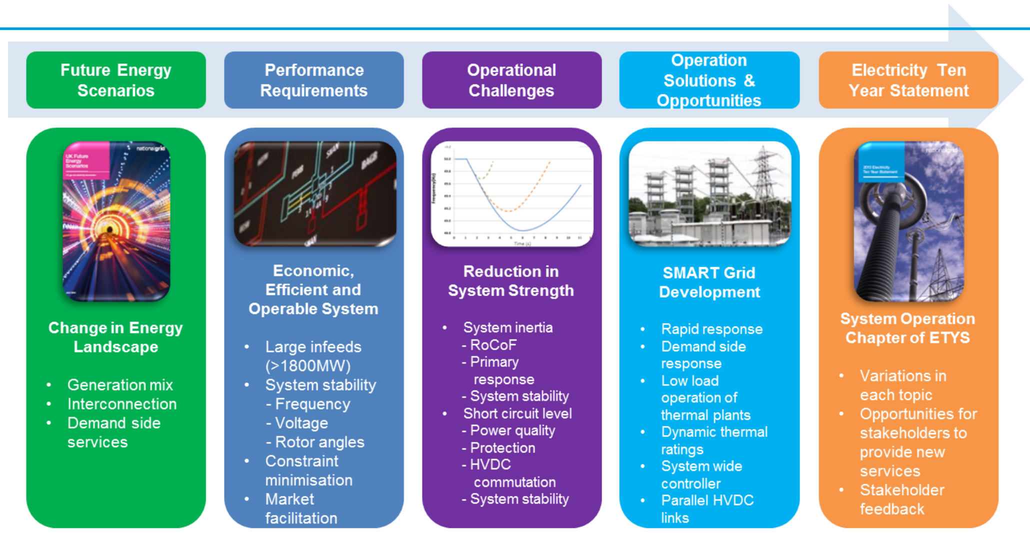


***Figure 2** System Operability Framework*

[1]http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/
[2]http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/Current-statement/

This, however, is not the only factor, nor is there a linear relationship between the levels of NSG and the scale of other potential issues described in this report. The following factors also need to be considered:

- Expected changes in demand side, e.g. energy efficiency measures and offsetting the demand with embedded NSG may exacerbate the changes in voltage management, power quality and frequency containment. ;
- Increase in the use of new technologies such as series compensation, Current Source Converter (CSC) and Voltage Source Converter (VSC) High Voltage Direct Current (HVDC) links requires the characteristics of such technologies to be carefully studied to identify potential interaction with generator shafts (Sub Synchronous Resonance and Sub-Synchronous Control Interactions) and commutation failure.

SOF 2014 Highlights

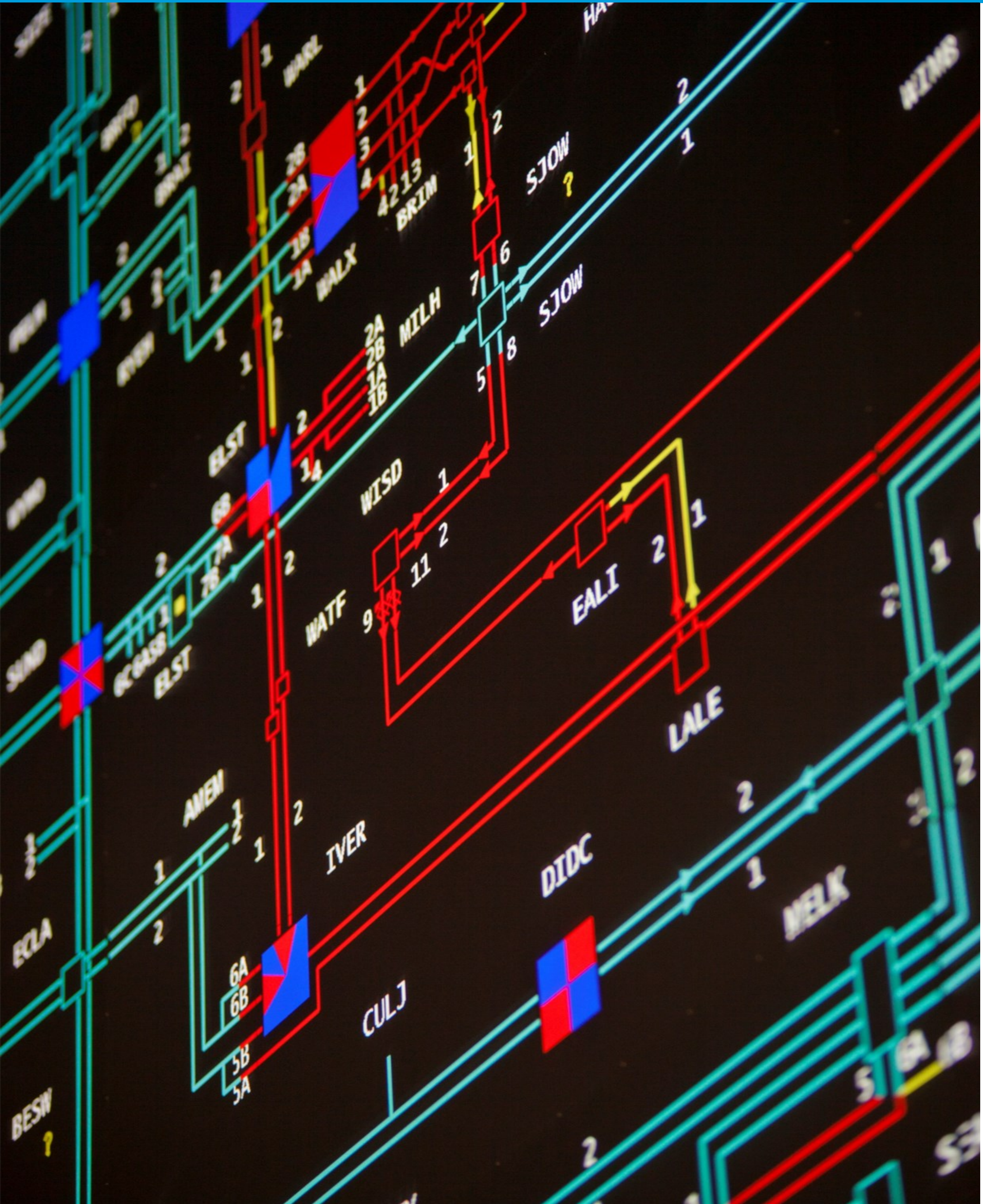
The main findings of this report can be summarised as follows:

- Given the expected reduction in system inertia, higher RoCoF settings, or alternative loss of mains protection approaches must be explored for new connections;
- Frequency containment needs to be kept under close review in the short term as in the absence of rapid frequency control measures, it can lead to significant increase in volume of response requirement.
- As NSG/Demand level increases across the system (at different locations), the system may require additional support (initially in the form of additional leading and lagging reactive power support). Additional assessment is required to establish how much of this requirement will be met by current investment schemes and the magnitude and location of the additional requirement which shall be conducted and reported in ETYS;
- The large-scale use of new technologies, such as VSC HVDC and series compensation will bring new challenges in terms of control system co-ordination and interaction, however these new devices, VSC HVDC in particular, could provide valuable system support in the future.

SOF 2014 Key Findings

The key findings of this work are:

- The Rapid Frequency Response delivery from NSGs which are capable of providing fast response may require new services to attract potential providers;
- The contribution of NSG to system stability is currently very limited as a number of mandatory Grid Code requirements applicable to synchronous power plants are not mandatory for NSG. SOF has identified a number of potential requirements such as power oscillation damping and Fault Ride Through capability for smaller units that can be delivered by NSG;
- The increase in distribution connected resources such as embedded generator, energy storage, and DSR requires better coordination of resources to ensure the impact on operability of the whole system is assessed;
- Improvement in the way network licensees study the system has been mentioned under different topics as part of SOF. An important tool to improve the study capability is the ability to validate the models used for this purpose. System monitoring using Phasor Measurement Units (PMUs) allows more detailed validation of the existing models and assumptions regarding system behaviour, and improves the study capability.



The System Operability Framework has been developed in order to outline the changes in system parameters and performance that are foreseen as a consequence of the change in the generation mix, characteristics of the loads, new technology and new market and industry governance arrangements. The analysis presented in this report is based on system studies and past experience of system operation. It is the intention of this report to highlight these findings to allow closer collaboration within the energy industry and allow developing and delivering the necessary solutions and services in the most suitable, economic and sustainable way.

There is an inevitable degree of uncertainty associated with the future of the energy landscape. National Grid seeks to provide an envelope to explore this uncertainty by producing Future Energy Scenarios (FES). The scenarios consider a range of environmental, political, economic and other drivers and their impact on the changes in future power generation mix and demand characteristics.

FES is used as a reference for future network development. The System Operability Framework (SOF) has been developed to investigate the impact of FES on GB transmission system operability in a systematic and holistic way. The framework assesses the potential changes in system behaviour over the next twenty years under each of the scenarios.

Changes in Future System Characteristics

The physical properties and dynamic performance of a power system is largely dependent on the type, volume and location of the connected generators and loads and the degree of electrical interconnection between them. Amongst other anticipated changes, the volume of non-synchronous generation (wind and solar power plants and interconnectors) connected to the system is expected to increase rapidly and significantly over the coming decades. This will have an impact on system operability:

- Reduction in system short circuit level;
- Greater variability of power flows;
- Changes in system inertia;
- Changes in system damping and susceptibility to device interactions;
- New dynamic control challenges associated with new and existing technologies;
- Changes in generation and demand characteristics.

System strength is a measure of the ability of the system to remain stable during and following disturbances and variations in system parameters. System strength can be divided into two main factors: system inertia and short circuit level. Both of these will reduce as the changes in generation and demand outlined in the FES materialise.

Due to the fundamental principles of their operation, synchronous generators naturally provide particular characteristic support to the system by contributing to system inertia, reactive power regulation, rapid response, voltage support and short circuit level above and beyond the load current of the machine.

Non-synchronous generators (NSG), on the other hand, are connected to the system via power electronics and the level of support available depends on the technology and the settings employed in the connections; NSG generally has a lower and different contribution to system strength compared to synchronous generation. From this it therefore follows that the lowest system strength is expected during times when a high proportion of demand is met by NSG.

Methodology

Historically, system limits and restrictions have been expressed mainly in terms of the total maximum level of instantaneous penetration of wind generation, and not of the various factors that might influence or improve the ability of the network to operate to these and other pertinent metrics.

Through assessing system dynamics, variations in wind power output and the effect of demand variation throughout the year, the System Operability Framework allows a more detailed picture of system operability requirements to be captured. The approach of the System Operability Framework is to capture and assess the year-round system characteristics that the system operator would face. This is first informed by system behaviour in previous years and then extrapolated according to FES to express the operating conditions for future years. The framework then calculates the duration and the extent of system constraints for those future years, taking into account the inherent uncertainties and sensitivities of FES and how system limits may be approached with the tools and technology currently available.

For each area of system characteristic the above is achieved by determining what percentage of hourly demand may be met by NSG in future years based on the previous year's hour-by-hour variation in generation output for each fuel type and extrapolating for future years in line with the expected levels of installed capacity for each fuel type.

It is important to emphasise the difference between NSG capacity and NSG/Demand ratio in this methodology: NSG capacity refers to the total installed wind and solar generation and interconnector (importing into GB) Transmission Entry Capacity (TEC) whilst the NSG/Demand ratio refers to the actual output of these NSG sources as a fraction of the demand as seen at the transmission level at a given point in time, taking into account the efficiency and load factors of the specific technologies (either nationally or regionally).

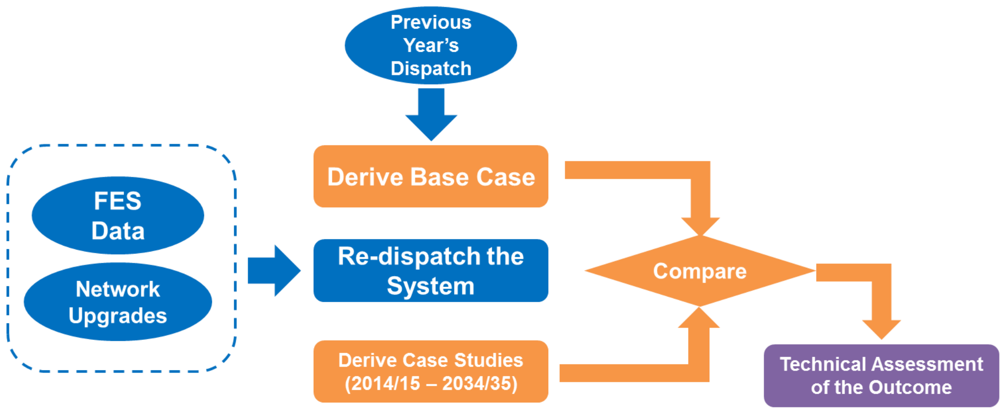


Figure 3 SOF Model

$$\frac{NSG}{Demand} = \frac{Transmission\ Connected\ Wind\ and\ Solar\ Generation\ Output + HVDC\ Interconnector\ Flow\ (Importing)}{Net\ Demand + HVDC\ Interconnector\ Flow\ (Exporting)}$$

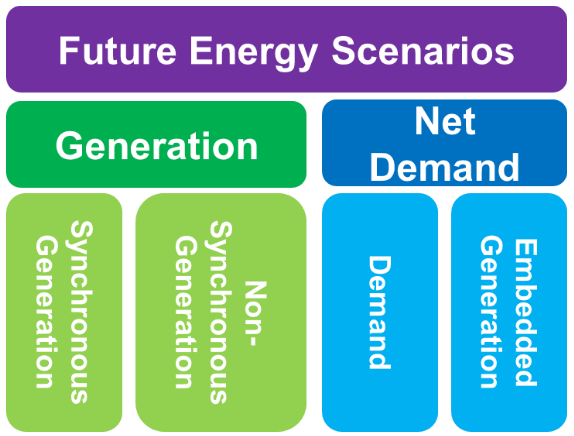


Figure 4 Future Energy Scenario Data in SOF Model

This methodology assumes that the overall levels of non-synchronous generation production as a proportion of installed capacity do not change, i.e. potential changes in future wind turbine design and generator efficiency are not accounted for and are noted as a risk that the actual level of NSG present on the system in future years may be greater than highlighted in this report. A similar effect could arise from the implementation of large-scale energy storage systems, demand side response and similar technologies.

Flow across interconnectors has been assumed to have the same trading profile as in previous years.

The SOF Model uses the re-dispatched system to calculate:

- System inertia duration curves;
- Short circuit level regional duration curves;
- NSG/Demand ratio.

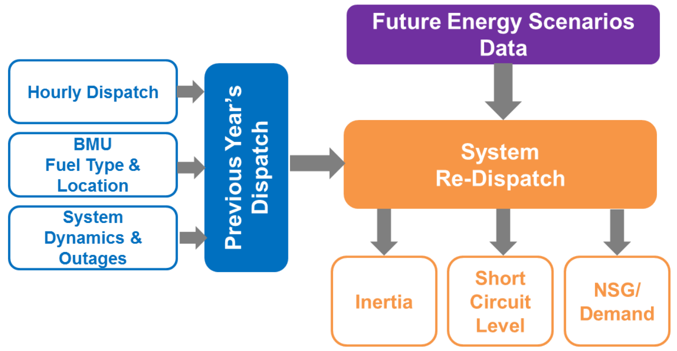


Figure 5 SOF Process

This report contains the results for system assessment from current year up to 2034/35 for all FES scenarios:

- Gone green;
- Slow Progression;
- Low Carbon Life;
- No progression.

The main differences between the scenarios are the levels of affordability and sustainability. These are driven by different assumptions with regards to future economic, political, technological, social and environmental developments, e.g. Slow Progression and No Progression both assume a slow UK economic recovery and the 2020 environmental targets being missed, whilst Low Carbon Life and Gone Green both assume a fast economic recovery and carbon reduction targets being achieved. A more detailed description of all of these scenarios can be found in the 2014 Future Energy Scenarios document (published on 10 July 2014).

All assessments and findings presented in this document are based on the assumption that the future generation units are compliant with the Grid Code in its current form, unless otherwise stated.

The factors that restrict the system in accommodating its maximum NSG production have been identified and the solutions that are considered to be suitable and feasible from a technical point of view have been summarised in the Conclusions section. These solutions will then be subject to full evaluation and appraisal via the energy industry governance arrangements.

The following figure illustrates the phenomena assessed in this report and their impact on system operability. As FES is updated annually, this report and the range of topics covered will also be reviewed and updated every year to accurately reflect each of the scenarios.

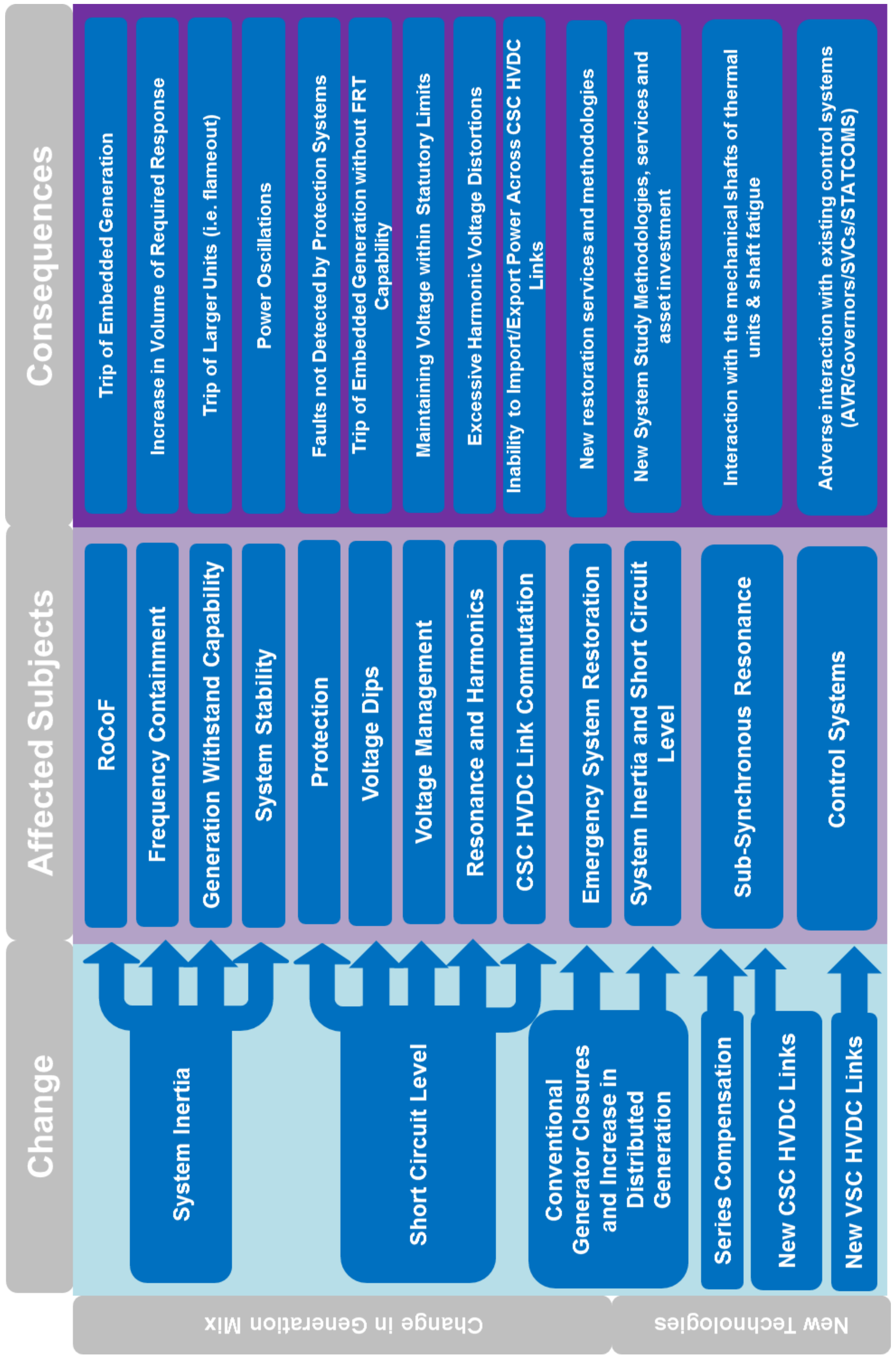


Figure 6 *SOF 2014 Topics*

2.1
Key Messages

- Rate of Change of Frequency (RoCoF) relay setting change would reduce RoCoF as an operability risk.

- Frequency containment remains an area that needs to be kept under close review in the longer term, given that RoCoF relay setting change will only apply to stations with capacity above 5MW. Increased levels of new response service requirements will be driven by new offshore wind power parks, large nuclear generators and a few particular Combined Cycle Gas Turbine (CCGT) projects exceeding 1800MW, which under all FES scenarios are anticipated to first connect around 2018/19.

- If successful, the Network Innovation Competition project on Enhanced Frequency Control Capability will help assess and deliver required solutions. National Grid is continuing to assess the volume of this requirement and the technical and commercial systems that this requires.

2.2
Background

System inertia is a key measure of how strong the system is in response to transient changes in frequency and it also supports the damping of small perturbations in frequency that left undamped can give raise to inter-area modes of oscillation. Inertia is the sum of the energy stored within the rotating mass of the machines (generators and motors) connected directly to the system . Low system inertia increases the risk of rapid system changes, e.g. severe faults or loss of load or generation, leading to system instability, therefore it is important to estimate and monitor system inertia to ensure that a sufficient level is always maintained to secure against the consequences of demand and/or generation imbalance that might instantaneously arise as a result of a secured event as defined in the National Electricity Transmission System Security and Quality of Supply Standard[3] (NETS SQSS).

Transmission-connected synchronous generators are made up of very large rotating elements weighing several tons and because of this mass, they present a significant resistance to any change in machine speed that may be triggered by a change in the electrical power balance of the transmission system. Being directly coupled to the system, the energy stored in the rotating mass is released into the system in situations where the electrical system is slowing down, and stored as kinetic energy of the mass when the system speed is rising, thereby slowing the rate at which the electrical speed of the system (system frequency) would otherwise vary due to a mismatch between generation and demand.

Conversely, most NSG are de-coupled from the system due to different technology being used in this type of generation – technology that converts asynchronous or DC power into AC power aligned with the system frequency via the use of power electronic devices. This therefore prevents typical NSG from contributing to system inertia, i.e. when NSG displaces synchronous generation, the overall system inertia decreases.

Wind generators connected to the system could in future contribute to the overall system inertia by providing “synthetic inertia” - rapidly increasing the power output in response to a drop in system frequency. This capability is not currently covered by the Grid Code and the commercial arrangements as more work is required on assessing the technical parameters and establishing the volume and cost benefit of the capability to provide such service.

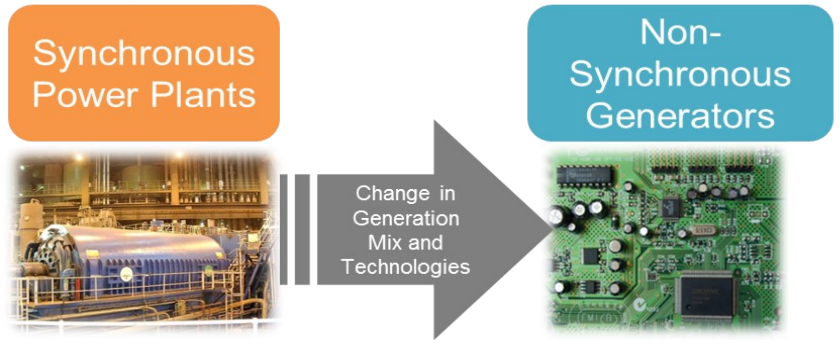


Figure 7 *Synchronous vs. Non-Synchronous Generation Sources*[4]

Change in system inertia has a direct effect on:

- RoCoF;
- Frequency containment;
- System stability.

In other words, when there is a larger amount of energy stored in the system, the rate of change of frequency is lower, the amount of required frequency response is smaller and the system is more stable following a disturbance.

[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/System-Security-and-Quality-of-Supply-Standards/
[4] Courtesy of Drax Group plc http://www.drax.com/

2.3 Rate of Change of Frequency

As highlighted above, the inevitable consequence of generation and demand imbalance during times of low system inertia is an increase in the RoCoF, usually following the loss of a large infeed. This has the potential to trigger the loss of mains protection relays and other protection systems based on RoCoF and to risk a deeper and more prolonged frequency depression ahead of current frequency response services responding to the event.

Impact on Operation

The initial RoCoF during the first second following a large generation infeed or load loss is an important parameter to measure to assess the potential subsequent loss of embedded generation. If the RoCoF during this initial period is sufficiently high to unnecessarily trigger loss of mains protection RoCoF relays on embedded generation, this could lead to a cascading loss of large amounts of embedded generation. Figure 8 describes the typical behaviour of a RoCoF relay in response to an intended protective action upon disconnection from the distribution network and how, when subjected to large step changes, the relays may operate unnecessarily to remove the generation from an otherwise healthy network.

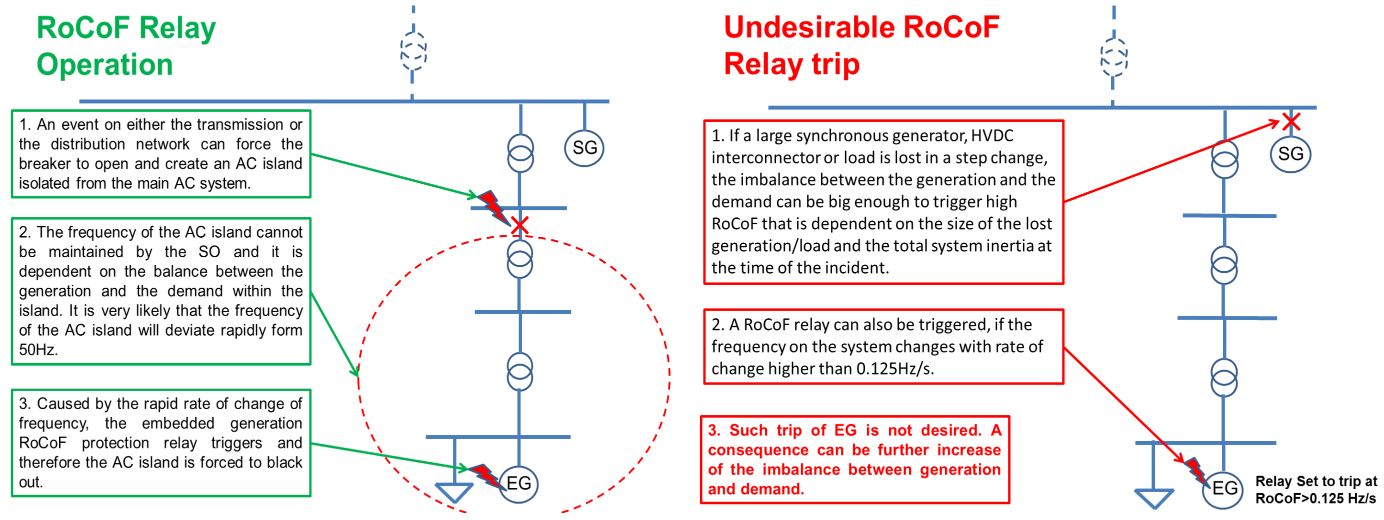


Figure 8 RoCoF Relay Operation

Work in progress and Key Findings

The system inertia analysis for 2014/15 demonstrates that, based on typical network operation across a year, the system can always tolerate a maximum of 922MW loss without violating the typical 0.125Hz/s RoCoF limit (assuming maximum cumulative frequency response ramp rate of 400MW/s), based on our understanding of typical embedded generator RoCoF settings. The largest operational infeed is expected to increase from the current 1320MW to 1800MW between 2018/19 and 2020/21, depending on the scenario:

- Gone Green 2019/20;
- Slow Progression 2018/19;
- Low Carbon Life 2020/21;
- No Progression 2018/19.

Under each of the scenarios this largest loss increase to 1800MW is triggered not by the connection of new larger nuclear power stations or Round 3 offshore wind generation projects, but is instead initially driven by new CCGT connections.

In Table 1 the maximum loss of infeed tolerance across a year is displayed whilst respecting the typical RoCoF limit of 0.125Hz/s; in tables 2 to 4 the effect of raising the RoCoF limit is examined up to a maximum level of 1Hz/s. This is the highest level of a single infeed that can be supported without additional constraints and other actions elsewhere on the system. In this analysis the amount of response held each year is assumed to match the maximum loss in place at that time, noting that as per the discussion above the maximum system loss for which response would be held would increase in 2018-2021 dependent on the scenario being studied.

Table 1 Loss of Infeed Tolerance 100% of Time to Maintain 0.125Hz/s Limit at All Load Conditions

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	922MW	922MW	922MW	922MW
2024/25	232MW	257MW	276MW	637MW
2034/35	263MW	212MW	242MW	397MW

Table 2 Loss of Infeed Tolerance 100% of Time to Maintain 0.3Hz/s Limit at All Load Conditions

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	1384MW	1384MW	1384MW	1384MW
2024/25	348MW	385MW	415MW	955MW
2034/35	395MW	319MW	353MW	596MW

Table 3 Loss of Infeed Tolerance 100% of Time to Maintain 0.5Hz/s Limit at All Load Conditions

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	2306MW	2306MW	2306MW	2306MW
2024/25	581MW	643MW	692MW	1592MW
2034/35	658MW	532MW	589MW	993MW

Table 4 Loss of Infeed Tolerance 100% of Time to Maintain 1.0Hz/s Limit at All Load Conditions

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	4613MW	4613MW	4613MW	4613MW
2024/25	1162MW	1286MW	1384MW	3185MW
2034/35	1317MW	1064MW	1178MW	1986MW

From the above it is clear that the recent Distribution Code change to ensure a higher RoCoF setting on embedded generators of capacity higher than 5MW would in short-term facilitate larger infeeds on the system without the risk of cascading losses, however for with RoCoF settings at stations smaller than 5MW remaining unchanged at this time, residual risk still remains.

To summarise, Tables 5 and 6 show the percentage of time that RoCoF would exceed 0.125Hz/s and 0.5Hz/s respectively under each scenario. This shows that if the typical setting remained at 0.125Hz/s, for example, there would be a requirement to either constrain the largest infeed or hold much greater amounts of frequency response 92% of the time across the year by 2024/25 under the Gone Green scenario (the drop from 92% to 90% between 2024/25 and 2034/35 in Gone Green is due to new large synchronous plant connections). Further investigation has demonstrated that 1Hz/s is expected to occur less than 1% of the time across all of these scenarios. The rate at which the challenge grows varies between the scenarios depending on the estimated connection dates of large synchronous and non-synchronous generators; further results can

Table 5 Percentage of time RoCoF>0.125Hz

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	19%	19%	19%	19%
2024/25	92%	38%	88%	23%
2034/35	90%	96%	93%	82%

Table 6 Percentage of time RoCoF>0.5Hz

Year	Gone Green	Slow Progression	Low Carbon Life	No Progression
2014/15	0%	0%	0%	0%
2024/25	5%	1%	2%	0%
2034/35	8%	8%	3%	1%

To further emphasize the effect that changes in the generation mix are having in driving reduction in system inertia, Figures 9 to 12 describe the estimated effect on overall system inertia (H) changes for each of the scenarios, based on a maximum wind power output of 70% (the load factor used in the economic analysis approach to boundary transfer planning as described in the NETS SQSS Chapter 4). It can be seen that the system inertia is expected to decline most rapidly against the Gone Green background, but also follows a path of decline in the other scenarios.

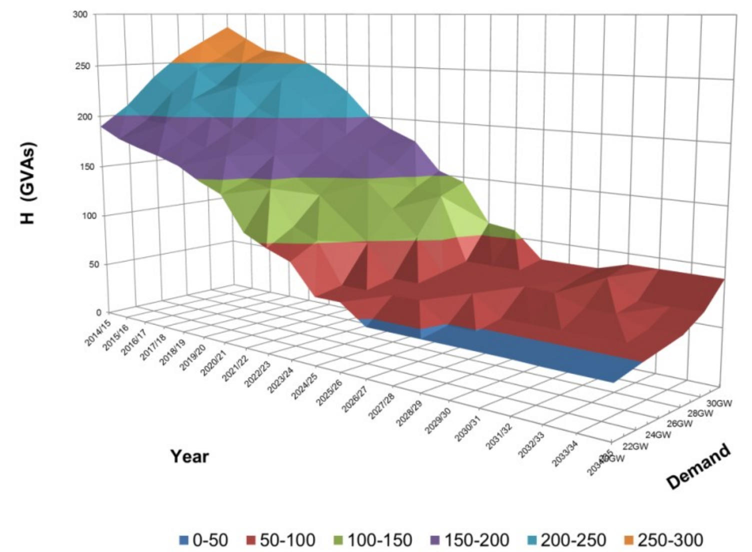


Figure 9 System Inertia (H) Changes for Gone Green Scenario at 70% Wind Power Output

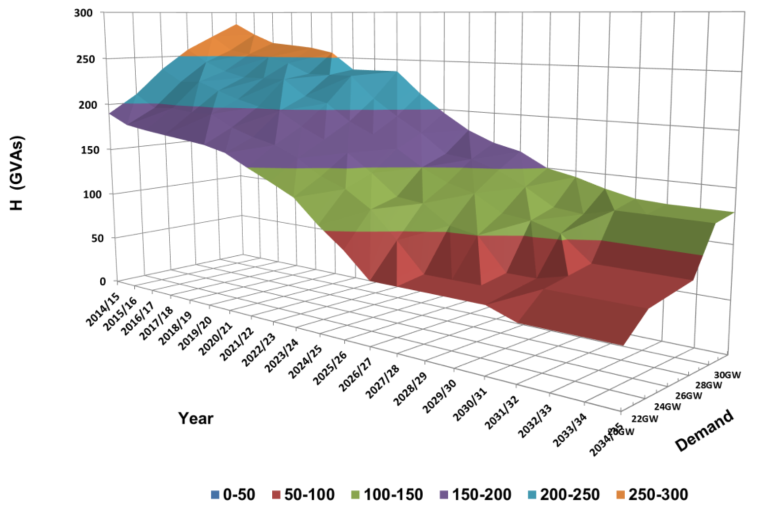


Figure 10 System Inertia (H) Changes for Slow Progression Scenario at 70% Wind Power Output

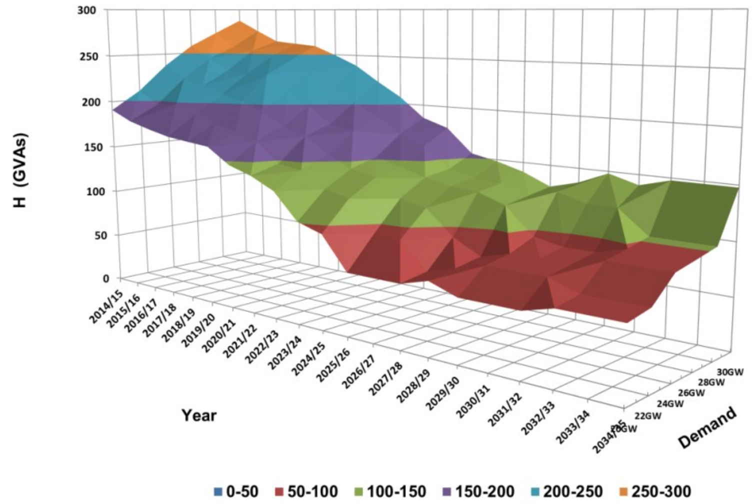


Figure 11 System Inertia (H) Changes for Low Carbon Life Scenario at 70% Wind Power Output

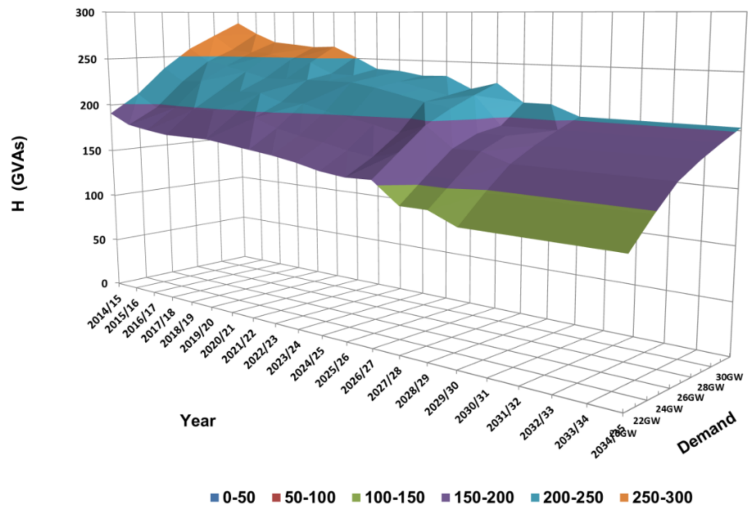


Figure 12 System Inertia (H) Changes for No Progression Scenario at 70% Wind Power Output

Mitigation

The RoCoF risk can currently be managed by temporarily constraining down the power output of the largest infeed during times when the loss of this infeed would otherwise cause the RoCoF to trigger large amounts of RoCoF relays. Constraining other synchronous plants into service in order to increase the level of inertia present on the system is another option, until such time that the protection relay RoCoF limit is increased. Without changes to the RoCoF relay setting, given the increased exposure identified in Tables 1-4, the cost of continuing to adopt this approach would increase significantly.

The joint Grid Code and Distribution Code work group GC0035 was formed to assess and facilitate the threshold change to 0.5Hz/s for synchronous generators and 1Hz/s for non-synchronous generators above 5MW that is expected to be fully implemented in August 2016. The work group is now examining requirements for smaller generators. The results from generator stress tests have been taken into account in the review process.

GC0042 has proposed for new data sets to be provided regarding the location and installed capacity of embedded generation; this will enable the System Operator (SO) to quantify where and what amount of embedded generation is using each of the settings.

National Grid has also applied for Network Innovation Competition[5] funding for a major project – EFCC[6]– which can contribute to RoCoF management and mitigation by identifying and trialling new frequency containment measures. Ofgem's decision with regards to the funding approval for this project will be available by November 2014.

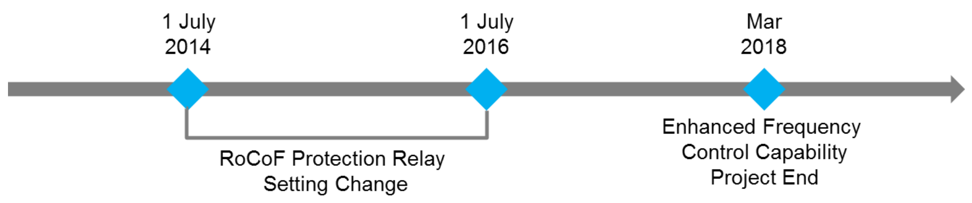


***Figure 13** RoCoF Timeline*

Additional possible approaches to the declining system inertia are being considered; several concepts are currently at a research and development stage involving National Grid, universities, major suppliers and other industry partners. These include:

- Examining the market and technical opportunities surrounding the de-clutched operation of synchronous generators to increase system inertia;
- Examining the market and technical opportunities for new synchronous compensation units;
- Examining the ability to utilise stored energy or enhanced control settings on NSG sources to simulate an inertia-like response;
- Examining the ability to incentivise higher demand upon the system during periods of high NSG availability and otherwise low system inertia to support greater levels of synchronous generation across such periods;
- Examining the role energy storage may have in minimising the effective NSG on the network by increasing system demand at those times.

National Grid would welcome further discussion with members of the industry in all of the above areas, and would also welcome the opportunity to further develop partnership proposals with them and suppliers over potential implementation projects suitable for NIC funding in future years.

[5]https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition
[6]https://www.ofgem.gov.uk/ofgem-publications/87210/ispefccnget.pdf

Frequency containment is a set of actions that ensure the changes in frequency following a loss of generation or demand are controlled, allowing the frequency to return to 50Hz as soon as possible and without exceeding the operational limits.

Sufficient levels of system response have to be scheduled by the system operator to maintain the frequency within statutory levels. Response to a system incident, however, is not instantaneous. As discussed above, lower system inertia leads to a higher RoCoF following a loss of infeed or demand. High RoCoF causes the frequency to change very quickly and in the case when a large infeed is lost, the frequency may drop to the lower limit and below before a sufficient level of response has had time to start responding the event.

The amount of response required for low system inertia scenarios is estimated by modelling the cumulative ramp rate of all units providing reserve response. Currently, the units in frequency response mode typically tend to start providing response within 2 seconds of an event[7]. This delay varies slightly between different plants and is usually dependent on plant characteristics and delays in measurements.

Impact on Operation

With increasing RoCoF, it is not only important to hold the appropriate level of response for credible system losses, but also to ensure that the response can be delivered quickly enough. From the point of beginning to respond to the event, a generator will ramp up their power output based on a given rate defined by their technical capability; the minimum requirements of this capability are described in the Grid Code. The ramp rate describes the relationship between the time and the level of response that can be delivered by individual units.

Typical frequency response units have so far been operating with an aggregated ramp rate of 250MW/s that can be sustained for 6 seconds following a 1320MW infeed loss. The infrequent infeed loss as defined by the NETS SQSS has recently increased to 1800MW and several units of this size are expected to connect to the system in the future, as highlighted above. This requires the response units to be capable of having a 400MW/s ramp rate in order to arrest the frequency before it has reached

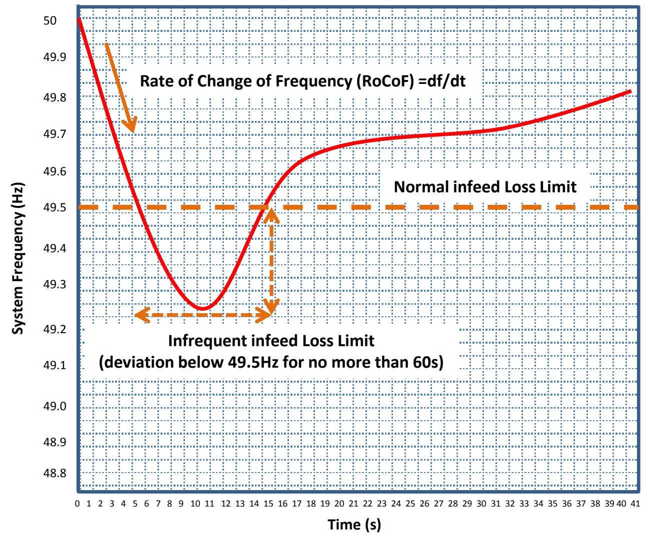


***Figure 14** Impact of High RoCoF on Frequency Containment*

[7]These requirements are set out in Grid Code section CC 6.3.7

Table 7 Required Response Rate for 0.125 to 0.3Hz RoCoF and the Year It is Required

Inertia (GW.s)	RoCoF (Hz/s)	Time[8] (to reach 49.2 Hz)	Response Rate (MW/s)	Requirement			
				Gone Green	Slow Progression	Low Carbon Life	No Progression
360	0.125[9]	9	**185**	2014/15	2014/15	2014/15	2014/15
225	0.2	4	400	2019/20	2024/25	2024/25	2029/30
205	0.22	3.4	489	2024/25	2024/25	2024/25	2029/30
180	0.25	2.4	679	2024/25	2024/25	2024/25	2029/30
150	0.3	1.2	1148	2024/25	2024/25	2024/25	2034/35

Mitigation

Achieving a higher amount of response within a much shorter time is likely to require new Enhanced Rapid Frequency Response (ERFR) services and changes to current network codes and frameworks.

Grid Code Working Group GC0022 was previously set up to evaluate the feasibility of rapid response from NSG. A number of R&D projects have also been investigating this, e.g. rapid frequency response from HVDC sources by University of Strathclyde, and from demand side customers and offshore wind turbine generators by Imperial College.

In addition to the above, a 2014 Network Innovation Competition submission by National Grid proposes to trial technologies that could be able to provide enhanced frequency control.

EU Requirements for Generators (RfG), Demand Connection Code (DCC) and HVDC Connection Code (HCC) have all considered frequency containment as part of the drafting process and there are various provisions for this subject within these codes.

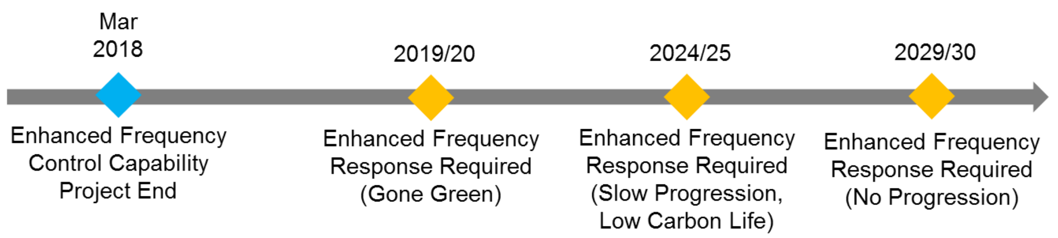


Figure 15 Frequency Containment Timeline

Enhanced Frequency Control Capability (EFCC) can be considered a solution to the reduction of system inertia in terms of reducing the power imbalance following a loss of infeed. Rapid active power imbalance compensation limits frequency deviations and leads to faster frequency recovery.

RFR can be delivered via:

- Converter connected infeeds, i.e. HVDC interconnectors and wind turbine generators;
- Fast demand side response;
- Energy storage.

Other possible solutions, such as voltage modulation, are at very early stages of feasibility analysis and therefore require in-depth assessment.

[8]The above assumes a 2s delay between detection/response activation time
[9]The actions currently taken to protect against RoCoF removes such high df/dt as a challenge for frequency containment

On a regional level, the displacement of conventional synchronous generation (whilst response and support similar to that of synchronous generation is not available from NSG or other sources) will also lead to a higher likelihood of instability following a disturbance, such as a double circuit fault. This is due to the lack of contribution and post-fault voltage support provided from current NSG as compared to the synchronous generation, noting that at a regional level the contributing NSG are unlikely to be in locations directly equivalent to the synchronous generation displaced across the FES backgrounds considered.

Due to the nature of the GB power system, different regions of the system will inherently have different tolerances to the level of inertia required to maintain stability within the required limits.

Impact on Operation

The level of inertia in a region is an important factor in the operation of the power system during the initial period of a disturbance or a fault. It is crucial to have sufficient inertia on the system so that the system remains stable after, for example, a short circuit fault.

In such a scenario a system without a sufficient level of inertia can experience a large frequency disturbance resulting from the instantaneous local voltage depression across a region, followed by slow voltage recovery.

Stability is achieved not merely by the rapid provision of power and frequency dependent behaviour discussed above, but also by ensuring that sufficiently dynamic reactive power reserves dispatched from the available providers stabilise and recover the voltage in the area. This prevents the disturbance from giving rise to large power angle swings that could complicate the synchronous generation and NSG return to normal operation following a fault.

In the context of regional stability much of the analysis focuses upon the consideration of the behaviours of synchronous generators and loads. As shown in the figure below, the NETS SQSS requires that after a disturbance, the generator should remain synchronised and not experience pole-slipping, and that the initial rotor angle movement should stabilise within 20 seconds following the disturbance.

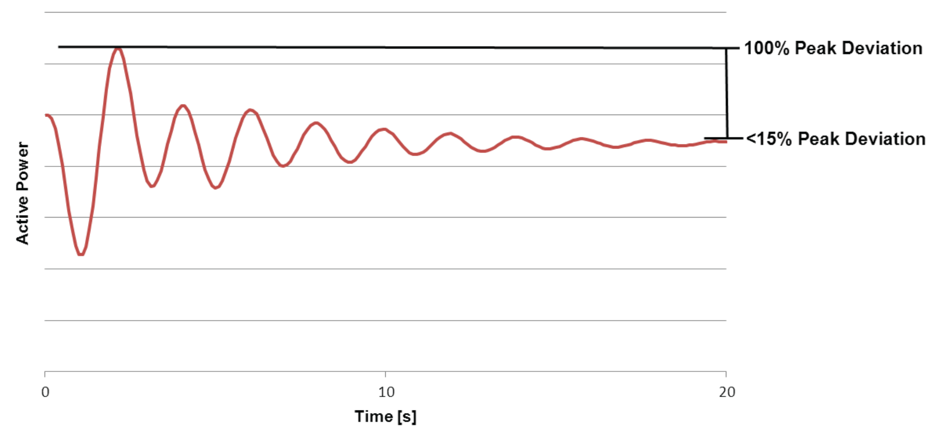


Figure 16 NETS SQSS Power Oscillation Damping Requirement

Work in progress and Key Findings

Four regions have been identified for the analysis of regional stability, on the basis of the scale of NSG already connected and anticipated to connect in these regions, and how this may over time impact existing transient stability management considerations in these areas. These regions are Scotland, South West, South East and North Wales.

Transient stability assessment has been undertaken for each of these areas against the FES background.

There may be some instances in Scotland and North Wales where the actual NSG output seen on the system already requires various real-time actions to be taken to accommodate the power infeed from these sources. This currently occurs sufficiently rarely and for sufficiently short periods of time for additional generator response and other real-time operational actions to be a more economic option ahead of asset investment once these occurrences become more frequent.

Mitigation

Most of the limitations associated with the capability to accommodate additional NSG capacity are due to insufficient pre-and post-fault dynamic reactive power support. The mitigation options should therefore look to increase capacitive reactive power response from a range of sources:

- New synchronous generators;
- New and existing NSG;
- VSC HVDC links;
- Dynamic reactive power compensation devices.

Table 8 Enablers for increasing the NSG Accommodation Capability

Region	Enablers for Increasing the Capability
Scotland	■ Additional dynamic capacitive reactive power support near the Anglo-Scottish Boundary ■ Sufficient level of inertia locally (regional inertia) ■ Improved Power Oscillation Damping (POD) capability
North Wales	■ Additional inductive and capacitive dynamic reactive power support
South East	■ Additional capacitive dynamic reactive power support
South West	■ Additional dynamic capacitive and inductive reactive power support

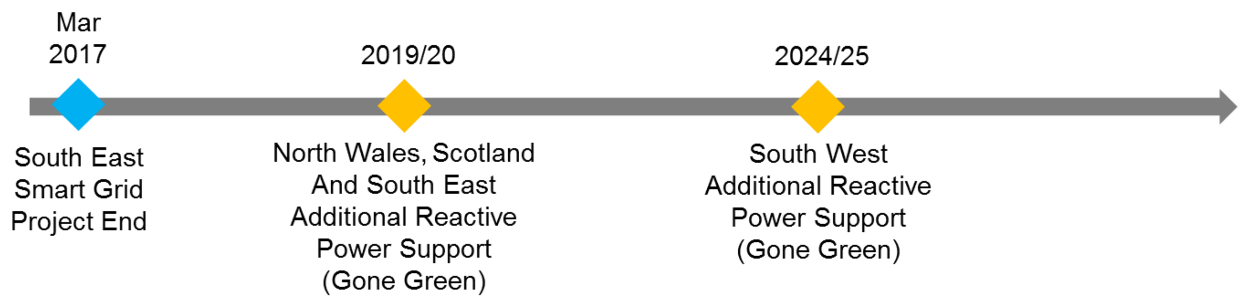


Figure 17 Regional Stability Timeline

Generator turbine control is designed to be able to withstand load rejection. The ability to withstand load rejection from base load is usually tested during commissioning. In a system with low inertia and high RoCoF, however, the generator turbine may trip due to rapid acceleration of the turbine generator (for steam turbines) and rapid reduction in the fuel-air ratio (flame-out). This condition is more often reported for gas turbines.

Impact on Operation

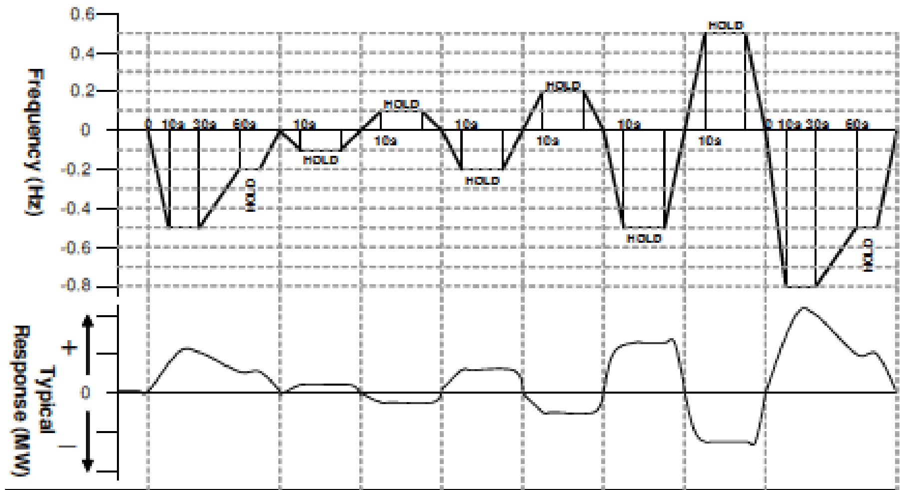
Generator part-load or full-load rejection can result in a significant and almost instantaneous loss of power infeed. Depending on the size of the generator, this may have an impact on frequency control if the generators cannot withstand a high RoCoF following an initial large infeed loss, leading to a cascading infeed loss.

Work in Progress and key Findings

The existing fleet of turbine generators are tested against the requirements set out in the Grid Code, illustrated in the figure below for each Module Load Point; "HOLD" indicates the delay (this is explained in more detail in the Operational Code, section OC5 Testing and Monitoring). The capability of the units to withstand such conditions in a real system operation scenario is uncertain, although the flame-out condition at high RoCoF has been reported in gas turbine generators by other system operators. Other generators, including NSG are not known to have this risk. Feedback received so far from generators and manufacturers suggests this should not be a risk for RoCoF lower than 1Hz/s; this level of RoCoF is not expected to occur for more 1% of the time over a year until at least 2034/35.

Mitigation

The current frequency response capability test procedure involves the injection of a frequency signal with a high rate of change; there is a delay between positive frequency change and negative frequency change. The Grid Code work group GC0035 plans to investigate generator RoCoF withstand. In addition to this, further discussions with manufacturers are underway to establish if this presents an operability risk.



Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

Figure 18 Frequency Response Capability Test Criteria

3.1
Key Messages

- Short circuit level is expected to continue to reduce between now and 2034/35.
- Voltage and reactive power management currently remains a challenge; work currently in progress will ensure than an effective mitigation approach is followed.
- Synchronous generation decommissioning, especially in the North East of England, North Wales and Scotland, in conjunction with rapid growth in distribution connected micro generation highlight the need for a more stringent approach to Fault Ride Through (FRT) requirements for embedded and micro generation units.
- Other aspects of power quality, such as protection settings and harmonic assessments are the responsibility of the transmission owners. These are being studied and reviewed regularly by the Transmission Owners (TOs) in collaboration with the System Operator (SO).

Short circuit level is one of the traditional measures of AC power system strength. A high short circuit level (as measured by the balanced 3-phase fault current at a point of interest) indicates that the system is strong due to the concentration of generation and demand in the area being highly interconnected over a short electrical distance, and hence the system can remain resilient in the event of small disturbances on the network as per the performance levels defined in the Grid Code and the NETS SQSS.

Synchronous machines are the main contributors to short circuit level due to the way they are designed and operated and the concept of short circuit level is very much founded upon the assumption that the short circuit current being measured on the system is being derived from synchronous sources.

The majority of the generation from renewable sources is connected to the system via power electronic converters; the design of these converters allows a much smaller contribution to the short circuit level compared to synchronously connected generators, and the characteristics of that short circuit contribution in response to balanced and unbalanced faults can be very different from that seen from synchronous generation.

For these reasons, increase in NSG will result in a gradual decrease in short circuit levels, which is impacting on various aspects of system operation. It will also result in the use of the concept of short circuit level as a measure of system strength to be a less relevant indicator of system behaviour, which may have ramifications for how the industry exchanges data and demonstrates compliance with performance metrics in future.

Fault level variation has been evaluated for seven regions as shown below. The studies have been performed for a low short circuit level conditions, i.e. for minimum system demand periods for each of the years studies. Figure 20 shows the current short-circuit level for each of the regions as a percentage of the total system strength; this illustrates the strength of each of the areas relative to one another. Full results are presented in Appendix B.

Figure 19 *Short Circuit Level Calculation Areas*

Figure 20 *Minimum Short Circuit Level (2014/15)*

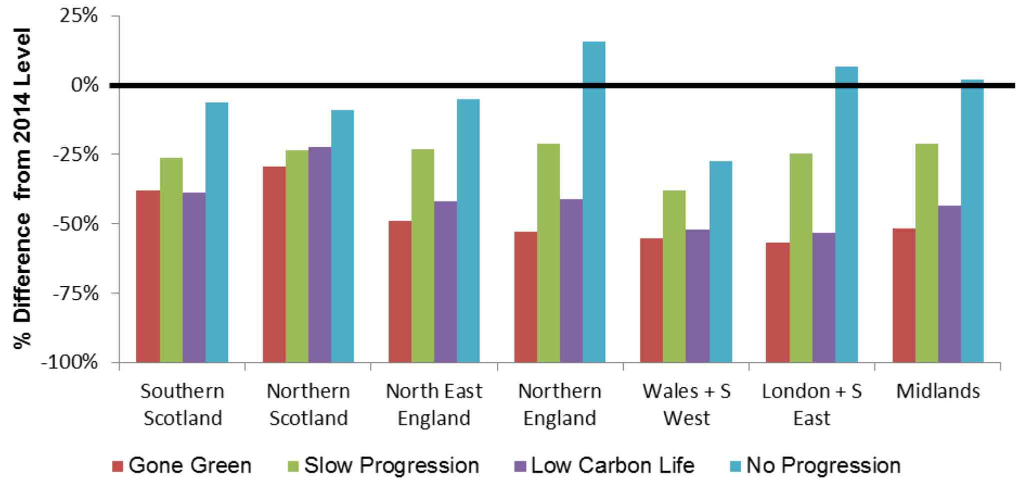


Figure 21 *Minimum Short Circuit Level Relative to 2014/15 Level(2024/25)*

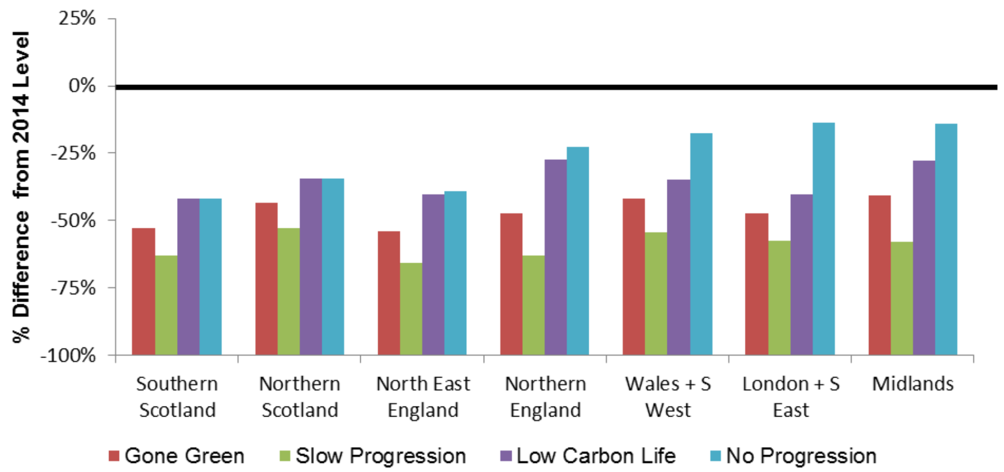


Figure 22 *Minimum Short Circuit Level Relative to 2014/15 Level (2034/35)*

Power Quality

Power quality affects the performance of the loads connected to the system and is therefore an important aspect of power system operation. All electrical loads connected to the power system have been designed in such a way that their correct operation and performance rely on an adequate power supply. The suitability of the power source can be defined in terms of:

- Voltage magnitude;
- Frequency;
- The shape of the voltage waveform (harmonic content).

A pure voltage and current waveform is represented by an ideal sine wave with the frequency of 50Hz.

There is a direct correlation between power quality and system strength. In general, the stronger the system, the easier it is to maintain power quality to the required standard. With the reduction of short circuit levels expected in the future, it is possible that power quality issues may become more apparent. This section further explores the following four aspects:

- Protection;
- Voltage management;
- Voltage dips;
- Harmonics.

3.3 Protection

The objective of protection systems is to detect and safely isolate faulty equipment as quickly as possible, before the fault affects the wider system. Protection systems are designed to have a very high degree of reliability, however they depend on the short circuit current infeed being high enough to trigger protection relay operation.

Impact on Operation

Transmission protection systems consist of two main systems operating simultaneously and independently from one another, and a backup protection system. The impact that low short circuit level can have on protection depends on the type of the protection scheme and the characteristics of that lower short circuit level used for protection relay operation in the earliest time periods on the fault; the most common protection schemes used on the GB system are summarised in Table 9.

In the cases below, protection failure may result in longer clearance times under back-up protection operation, and network instability over longer periods of fault on the transmission system than is catered for by the performance requirements set out in the Grid Code.

***Table 9** Short Circuit Level on Protection*

Protection Scheme	Operating Principle	Impact of Low Short Circuit Level
Differential Protection	Compares the current infeed and output from the equipment; if the difference between the two is greater than bias current, the relay is set to trip	If the difference between the currents is very small, it may not be detected by the relay
Distance Protection	Calculates the impedance at the relay point and compares it with the reach impedance; if the measured impedance is lower than the reach impedance, the relay is set to trip	Not affected if the ratio of voltage to current decreases following the short circuit.
Over-Current Protection	The operating time of the relay is inversely proportional to the magnitude of the short circuit current	This type of protection is the most likely to be affected by low short circuit levels, however these schemes are mainly used for back-up protection and therefore the consequences may not be severe, provided that main protection schemes are not compromised

With regards to the relay settings for individual circuit protection operation, there is a need to ensure that the protection device can discriminate between fault conditions associated with that circuit and those associated with other circuits or assets unrelated to that circuit. As the short circuit level falls, so too does the level of difference in fault current used to discriminate between disturbances on other elements of the transmission system or users' systems and those associated with the circuit in question. This could lead to a more extensive protective response to a fault at times of low short circuit level.

Work in Progress and Key Findings

There is currently a well-defined process to evaluate short circuit level and to assess the suitable protection settings. There is also ongoing work in the development and design of new protection approaches that would be less sensitive to the reduction in the observed system short circuit level.

Mitigation

The process to mitigate the impact of reducing short circuit level on protection systems is well defined and continuously reviewed by the protection engineers. Type registration processes govern the development of new protection systems; these are also clear and sufficient in managing these changes. The GB SO is in the process of liaising with the TOs to confirm an overall risk management approach exists and the key milestones for the delivery of this may be met on time.

3.4 Voltage Management

Voltage behaviour is the principal indicator of power quality. Voltage management relates to:

- The steady state behaviour of the voltage;
- The extent to which deviations are contained within a region;
- The ability of the system to contain the effects of any disturbance in steady state conditions.

During peak demand periods across all scenarios, the network continues to operate within the norms for voltage step change and voltage regulation for particular high boundary transfer conditions is achieved using a number of shunt-connected capacitors. However, at daily minimum system demand points across the period of April to October, high voltages have been observed during periods of low reactive power demand. This is due to the fact that reactive power demand (and the proportion of reactive power demand to active power demand) as seen at the Grid Supply Points (GSPs) has been reducing significantly over recent years. Figure below illustrates the shift in averaged minimum (average of three minimum values) active and reactive power demand, and the ratio between the two (Q/P ratio, where Q is the reactive power demand and P is the active power demand).

This reduction tends to be particularly noticeable overnight. In the last few years reactive power demand reached its annual minimum value at approximately 4-5am in late May or early July, but very low demands have also been observed in August and early January.

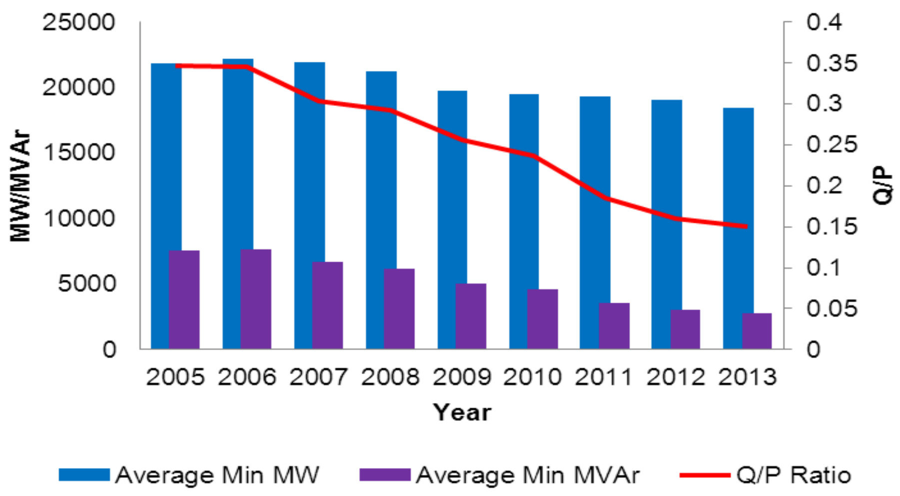


***Figure 23** Historic Q/P Ratio Trend*

There are several possible factors that can contribute to a reduction in reactive power demand:

- Increasing use of cables in Distribution Network Owner (DNO) and transmission networks;
- Changes in line loading patterns due to increase in embedded generation;
- Voltage control asset capability in certain areas;
- Energy efficiency measures (e.g. switch to energy efficient lighting);
- Changes in load characteristics (e.g. shifts between industrial and domestic loads).

It is difficult to pinpoint how much each of the above factors contribute to the overall reduction of reactive power demand as different factors may be dominant in different areas. This makes it complicated to precisely forecast reactive power demands more than a few months ahead. Recent analysis of the effect of embedded generation, however, has indicated that it alone has contributed to as much as 29% of the overall national trend illustrated above. As such, it is expected that as levels of embedded generation increase across the scenarios – in particular in Gone Green and Low Carbon Life – there could be a sustained decline in reactive power absorption at minimum demand periods across the network.

Impact on Operation

The overnight voltage profile in many areas (South East, Midlands and Scotland in particular) is approaching the upper boundary of the operational limits. It is important that this exposure is minimised since prolonged, frequent exposure to high voltage can have the following impact:

- Flashover risks;

- Asset overstressing and insulation breakdown;
- Wound equipment over-fluxing;
- Risk of circuit breaker re-strike during de-energisation;
- Increased risk of asset catastrophic failure .

Increasingly, reactive power is being exported from the GSPs onto the transmission system. Reactive power demand is measured by averaging the demand over every half hour period; the figure below illustrates the proportion of time the GSPs nationally have been net importers and exporters of reactive power in previous years.

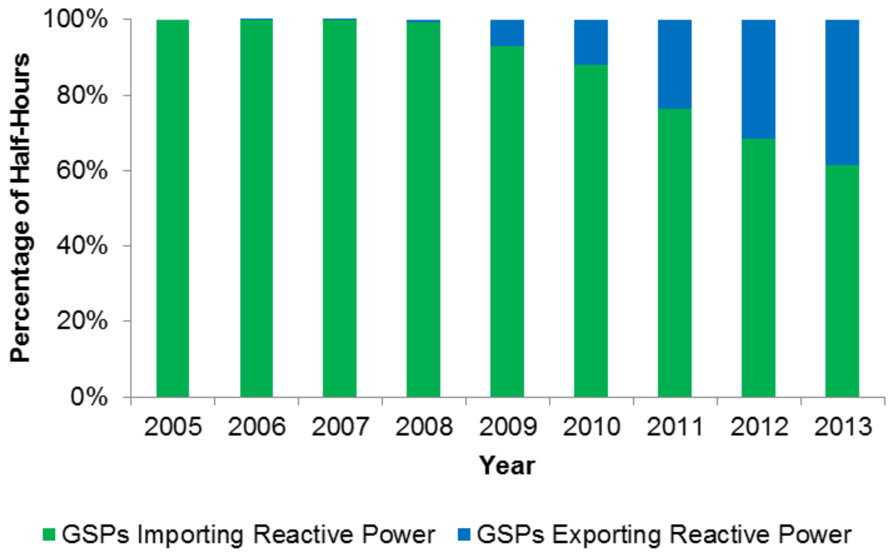


Figure 24 *Historic GSP Reactive Power Exchange*

In 2013, the distribution networks were a net supplier of reactive power to the transmission system 39% of the time. This suggests that unless the decline in reactive power absorption is not arrested, the duration and extent of voltage containment issues will only increase.

Work in Progress and Key Findings

The EU Demand Connection Network Code[10] is expected to be fully implemented by 2017. This, subject to a cost/benefit analysis, may potentially restrict the reactive power flows to and from the DNO networks onto the transmission system.

Figure 25 shows the regional historic averaged minimum Q/P ratios and a projection of three possible trends the ratio could follow in the future, depending on the actions taken until 2017 for the Low Carbon Life scenario: continue to rapidly decrease and become negative; decrease towards 0 and remain close to it (due to active power being imported from distribution network onto transmission network and circuit loading beginning to increase); remain close to current level due to asset investment or other actions on the transmission and distribution networks.

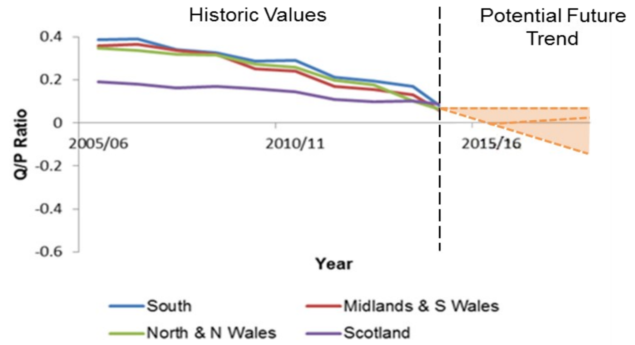


Figure 25 *Regional Q/P Ratio Trend Extrapolation*

[10] http://networkcodes.entsoe.eu/connection-codes/demand-connection-code/

Mitigation

During the last year the voltage assessment methodology between the GB SO and the onshore transmission owners (TOs) has been improved specifically for assessing voltage compliance across the GB transmission system for periods of low demand.

The amount of reactive power support available from synchronous generators is likely to reduce in the future. Under low wind conditions this results in low transmission system transfers and with growing interconnector imports can lead to a worst case transmission system effects on high voltage, particularly in the Scottish Borders, Northern England and the Midlands.

In addition to current study work, Grid Code Working group GC0042 Information on Embedded Small Power Stations and REACT project lead by National Grid and DNO companies is aiming to improve data and knowledge sharing between the DNOs and the SO. This will establish the extent to which the aforementioned factors are contributing to the drop in reactive power demand, and allow for more detailed modelling of the DNO networks to complement transmission level studies.

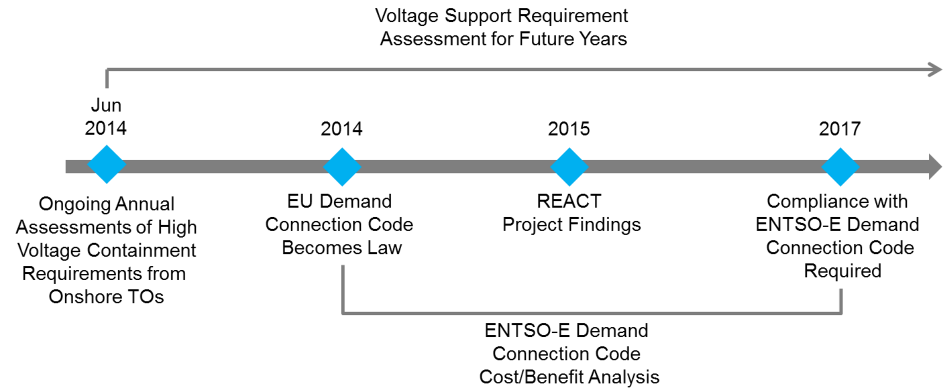


Figure 26 *Voltage Management Timeline*

The System Operator is currently managing the above issue by:

- Keeping the system voltage close to the lower limit during the day to allow a bigger head room for the rising voltage overnight;
- Switching out lightly loaded cable circuits in key areas;
- Optimising the use of reactive power compensation equipment;
- Contracting synchronous generators local to problem areas to absorb reactive power overnight.

New potential providers of reactive power support are being investigated. One such source could be Flexible AC Transmission System (FACTS) devices on transmission and distribution networks. Other sources of voltage and reactive power support could be offshore transmission and offshore generator asset reactive capability, and the use of Quadrature Boosters (QBs), wide area monitoring, automated control systems and auto-switching by the TOs in order to expand the range of operational actions available to the SO.

3.5
Voltage Dips

A transient voltage dip is a short-term (0 to 140 milliseconds) reduction in system voltage typically as a result of a short circuit, large machine start-up or transformer energisation. Short circuit events have the most severe consequences on voltage dips and are often unpredictable and unavoidable (e.g. due to adverse weather conditions). The extent and the duration of voltage dips need to be minimised due to their detrimental effects on generators and loads seeing the dip.

The depth and spread of the dip are largely dependent on the presence and performance of nearby generators - the GB Grid Code mandates that all generators connected to the transmission system and large generators connected at the distribution level must be able to remain connected for the first 140 milliseconds to 3 minutes, depending on the severity of the dip as part of the Grid Code Fault Ride Through (FRT) requirement.

The increase in NSG and closure of synchronous plants, however, cause a reduction in the transient voltage support capability of the network. In addition to this, a high proportion of large new generators are expected to connect geographically towards the edges of the network which may adversely influence the effectiveness of voltage control from these generators for the innermost parts of the network.

Impact on Operation

As the short circuit level decreases, the size of the area affected by a voltage dip will increase, as previously illustrated in the 2012 and 2013 editions of the ETYS. The effects of transmission voltage dips are not only observable across the transmission network, but are also observable on distribution networks in the vicinity of the fault (the effects are “3-dimensional”).

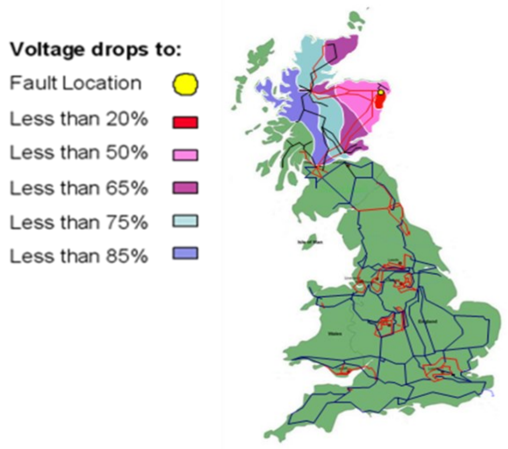


Figure 27 *Voltage Dip Spread Example - Fault at Peterhead (Current Summer Minimum Background)*

As many of the future voltage recovery support sources will be connected electrically distantly from the areas they are expected to support, the effective support of these sources will be lower. Given also that NSG are required to provide a less lagging output in comparison to a synchronous provider, the response available as NSG displaces synchronous generation will reduce. This will have the effect of further changing the characteristics of the network following a clearance of an electrical fault as it then recovers from that low voltage condition.

The installed capacity of distribution level micro generation (e.g. domestic solar PV) is expected to grow rapidly as per FES. These small generators currently do not have a strict FRT requirement and are only obliged to have FRT capability with respect to voltage dips if this is defined in the Connection Agreement between the DNO and the generator in accordance with the Distribution Planning Code (DPC 7.4.3.3). For this reason, if exposed to a dip, instead of supporting voltage recovery, large volumes of micro generation may disconnect. The Transmission System Operator can only observe the cumulative effect of these generators and demand, and has no visibility of the level of power generation and location of individual micro generation units; therefore there may be a risk of losing these units following a short circuit event on the transmission system.

Currently the installed capacity of micro generation nationally is around 10GW but it may double in the next decade, therefore FRT requirements may need to be defined for these units to ensure adequate economic and efficient reserves and support are available post-fault.

The current draft version of the EU Requirements for Generators code[11] has mandated FRT capability for smaller generators (down to 1 MW); internally National Grid is assessing the need case to aid such requirement, prior to any consultation regarding GB implementation of this code.

Work in Progress and Key Findings

Grid Code Working Group GC0062 is seeking to provide further clarity on the requirements for generators to remain connected under long duration fault conditions. This will provide consistency across all users connected to the transmission system to ensure the requirements of FRT are complemented with a design philosophy that in practice does not seek to exacerbate real network voltage dip conditions beyond those studied in the Grid Code.

Robust assessment of voltage dip risk requires detailed knowledge of the DNO networks which is currently not available for all regions. The results of previous studies rely on the accuracy of DNO assumptions and embedded generation forecasts (Grid Code work group GC0042 aims to improve this).

Mitigation

In view of latest study results on changes in short circuit level and extent of voltage dips both on the transmission and distribution levels, it is evident that a greater transient voltage support will be required on the system. Possible sources of such support are:

- Higher transient voltage support requirement from synchronous and non-synchronous generators;
- Fast dynamic reactive power support from FACTS devices;
- FRT capability of all generators connected at the

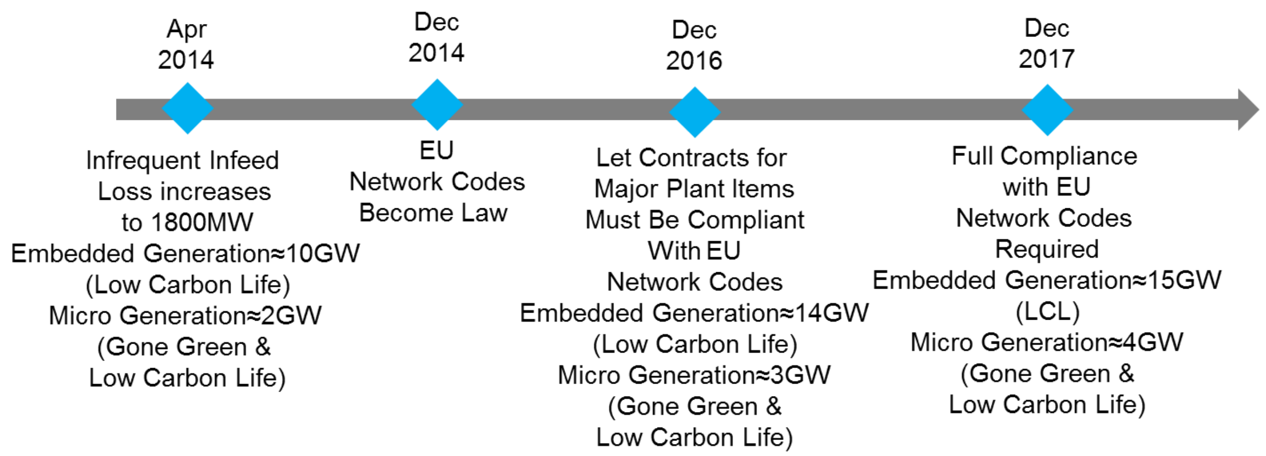


Figure 28 *Voltage Dips Timeline*

[11] http://networkcodes.entsoe.eu/connection-codes/requirements-for-generators/

Harmonics are waveforms of higher frequencies than the nominal frequency, which superimpose the original waveform, thereby creating an impure waveform compared to the original 50Hz sine wave.

Harmonics can be introduced in a number of ways. Some of the most common sources are non-linear loads: arc furnaces, arc welders and discharge lighting. Power electronic converters, railway traction systems, cable infrastructure and NSG also introduce harmonic content and have a different impedance compared to traditional loads. The combined effect of this is that there is a shift towards lower order harmonics (nearer 50Hz), causing an amplification of voltage distortion.

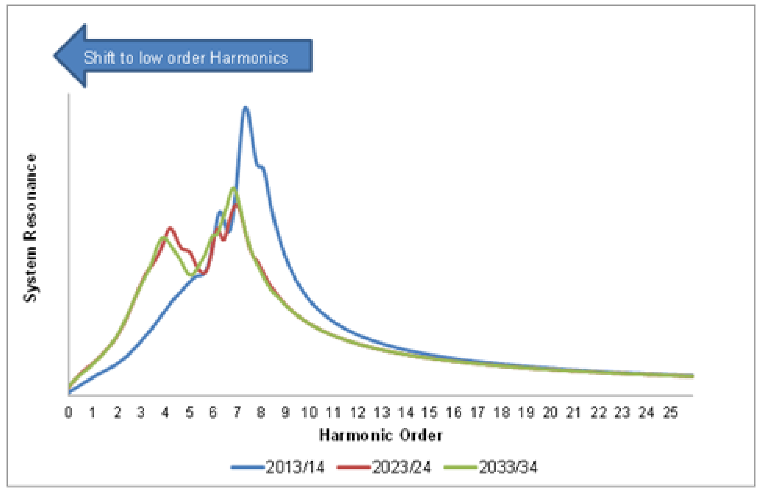


Figure 29 System Resonance Shift to Lower Order Harmonics

Impact on Operation

Harmonics have an impact on a range of operational aspects:

- Conductor heating;
- Increase in losses;
- Voltage distortion;
- Over-voltage under resonant conditions;
- Electromagnetic interference with communication circuits;
- Protection relay malfunction.

Voltage variation observed at a particular harmonic frequency is a function of the current injection and the network impedance at that frequency. This, combined with a displacement of synchronous plant, may cause a shift in network resonance towards the lower order harmonics, amplifying the already present levels of voltage distortion and adversely affecting power quality.

Although the above issues are expected to be mitigated during the connection design stage, there is a risk associated with the unpredictability of the aggregated behaviour of the various current and future technologies that can introduce a harmonic content. This could lead to having to constrain generation and interconnection or limit system access and certain network configurations to avoid harmonic vulnerability that is not possible to identify during the design and planning stages.

Work in Progress and Key Findings

The underlying assumptions made to evaluate long-term NSG impact on harmonics are only appropriate so far as to illustrate the expected trend in voltage distortion as a result of changes in network resonance. Based on this, it is not currently possible to accurately determine when harmonics may become a challenge for the system operator.

Harmonic assessments are, however, routinely carried out as part of the customer connection process in order to ensure that the injection of harmonic content outside of the planning limits is mitigated as per the Engineering Recommendation G5/4. These studies are carried out by the TOs over a wide range of scenarios: varying demand and generation backgrounds, different network topologies, outages and faults.

The challenge to the operator, however, is that as the short circuit level of the network reduces, the vulnerability of the network to a given distortion increases at the same time as the frequency at which the distortion occurs begins to move progressively

towards the fundamental frequency, making the solutions harder to identify and potentially requiring flexible solutions or additional sources of damping after the customer has connected to the system. Part of the solution is to improve the monitoring systems to track the effect of these changes and better model network volatility.

In England and Wales these studies will be further complemented by utilising Power System Monitor devices that measure existing voltage distortions at specific locations, allowing the network owner to ascertain the margin between existing level of distortion and the G5/4 planning limits. The Power System Monitor installation scheme is expected to deliver 75 permanent monitors and 25 portable monitors by 2015/16, providing coverage for 50% of substations in England & Wales. The criteria for monitor locations are:

- Geographically remote substations;
- Interface between 275kV and 400kV voltage levels;
- National borders;
- Multi-port 400kV substations;
- Central 275kV multi-port substations;
- Other strategic locations.

Various monitoring devices are also being installed in Scotland on key areas of the network to enable the observance and measurement of system parameters.

Mitigation

The existing tools, resources and expertise in assessing voltage distortion are considered to be appropriate for identifying and mitigating potential future challenges with respect to harmonics and network resonance. Once the Power Quality monitor installation programme is complete, the information obtained from these devices will provide an even greater level of confidence for all concerned parties.

4.1
Key Messages

- New technologies, especially those associated with series compensation and HVDC assets, bring a need for more extensive studies during the early design stages in order to avoid issues such as Sub-Synchronous Torsional Interactions (SSTI), Sub-Synchronous Resonance (SSR) and control system interference.

- The extent and timing of the potential adverse interactions is largely dependent on the specific technology, control settings employed and the distance between the generating units and series compensation and HVDC assets.

- The future availability of generating plant suitable to provide emergency restoration is of particular concern. Current restoration methodology is unlikely to be suitable in the longer term (10+ years); both new sources and new approaches to full or partial system restoration need to be investigated and consulted upon with the wider industry and stakeholders

- A range of activities, including investment in new assets, system study work and R&D, are currently in progress or will commence in the near future; the outcomes of these will aid better understanding of the extent and the potential mitigation needs and opportunities for this topic.

- The evolution of Distribution System Operators (DSO) is expected to be a major factor in the ability to deliver the most economic and efficient solutions to the limitations outlined throughout this report, thereby allowing a further growth in embedded generation and demand side services, whilst maintaining the required standards in terms of system operability aspects.

4.2 Background

The evolving use of new technologies is expected to enable the achievement of increased capacities and efficiencies from GB transmission assets. These new technologies can also bring new challenges. Series compensation, new HVDC links based on Voltage Source Converter, and ever increasing levels of NSG connections based on power electronic control systems all require detailed impact assessment to ensure that there are no adverse effects on the rest of the system.

This section explores in more detail the various effects and opportunities arising from rapid growth in generation sources and interconnection connected to the system via power electronic converters and controllers, and developments in the distribution networks and how the approach to system operation must adjust to facilitate these.

More information on National Grid processes for implementing new technology can be found in Appendix D—Network Innovation.

4.3 Sub-Synchronous Resonance (SSR)

SSR occurs due to the addition of series compensation onto the system, SSTI - due to the addition of HVDC. The potential effect of both SSR and SSTI on the network is the interaction with generator shafts, and in severe cases they can both cause shaft fatigue and failure. Other types of Sub-Synchronous Interactions exist between control systems and the transmission network and between control systems at particular complementary control frequencies, both of which will become increasingly relevant as regional levels of NSG increase.

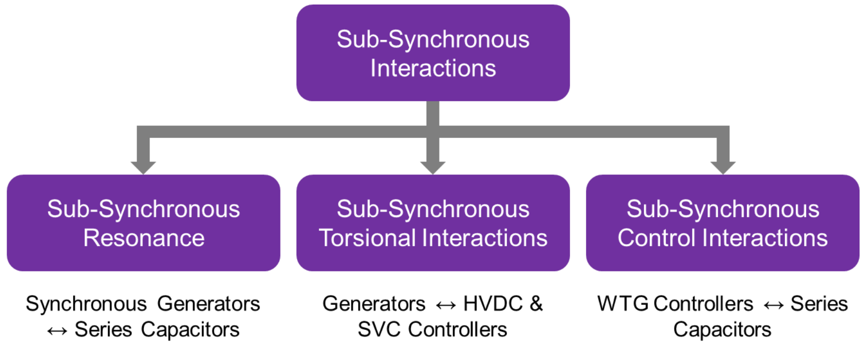


Figure 30 Sub-Synchronous Interaction Classification

Impact on Operation

In the case of the series capacitor, if the complement of the transmission network electrical resonant frequency (50- f_e Hz) is close to or coincides with one of the turbine-generator shaft natural frequencies of synchronous generators, the Sub-Synchronous Resonance (SSR) will take place, resulting in the potential for shaft oscillations, subject to the level of mechanical damping present in the shaft to restrict such oscillatory behaviour. If not damped out in good time, SSR can damage the turbine-generator shaft, resulting in loss of generation. The greater the degree of compensation, the higher the risk of SSR. This is also true for radially connected synchronous[12] generation (as a result of some network operating conditions).

In the case of HVDC Installations, there is a risk of a similar (but different) interaction - Sub-Synchronous Torsional Interaction (SSTI) - this time between the current/active power feedback loop of the HVDC control system and the turbine-generator shafts of neighbouring synchronous generators. This can also result in damaging shaft oscillations, but on a smaller scale than the series capacitor interaction.

Preliminary studies and mitigating measures are carried out at the early design stages.to eliminate operational restrictions on utilisation of these technologies (series capacitor, and HVDC links). This assessment requires complex system models that are continuously improved and updated.

Work in Progress and Key Findings

National Grid has developed a study framework for its assets that covers (for both series capacitor SSR and HVDC SSTI):

- Stage 1: Studies that can be carried out with the data already available to National Grid (screening studies);
- Stage 2: Studies that require generator shaft data (calculate shaft natural frequencies and damping);
- Stage 3: Studies required to determine SSR and SSTI mitigation measures (modify existing control system or design a new controller).

These assessments (as well as an annual network scan which ensures validity of the results) will be carried out at the design stage, and the mitigating measures such as modification to the control systems or addition of a new control system will be recommended to avoid the risk of SSR and SSTI. Studies relating to the Unit Interaction Factors (UIF) HVDC connections are already routinely carried out at the connection design stage. There is a dependency on the availability of the generator shaft data, and where such data is not available, site tests may be required to obtain such data.

[12]Amongst synchronous generators types, only thermal power plants are at risk. Hydro generators usually have a different shaft design which makes them immune against the risk of SSR/SSTI.

Apart from the above, the following projects are also currently under way:

- The Thyristor Controlled Series Capacitor (TCSC) project for installation at Hutton, due to be commissioned in October 2014;
- Scottish Power Transmission (SPT) are also installing Fixed Series Compensation at Moffat, Gretna and Eccles with passive SSR filters to be commissioned in October 2015;
- Western HVDC link project between Hunterston (Scotland) and Flintshire Bridge (North Wales) to be commissioned in October 2016.

Mitigation

In addition to the assessment framework outlined above, in case of series compensation National Grid has procured a TCSC unit that aims to not only remove the risk of SSR but also provides additional transmission capacity and an enhanced stability limit. National Grid also ensures the suppliers carry out extensive studies and design the necessary damping controllers for any generator which is identified at the screening stage as a potentially susceptible to SSR/SSTI.

4.4.1 Control System Interaction

With the increasing number of NSGs, FACTS, and HVDC converters connected electrically very closely together, and all having control systems which share the same value as an input (i.e. all use bus bar voltage as an input signal to respond to changes), there is a risk that by not studying such behaviours collectively, undesirable control interactions occur.

Power electronic control systems used in Static VAr Compensators (SVCs), FACTS devices and wind turbine control systems, particularly Doubly Fed Induction Generators (DFIGs) radially connected to a series compensated transmission circuit) can interact with sub-synchronous modes of the network, and cause Sub-Synchronous Control Interactions (SSCI). This control interaction can be worst in a network with low short circuit ratio. It can result in severe over -voltages, current distortion, tripping of additional facilities and damage to control systems.

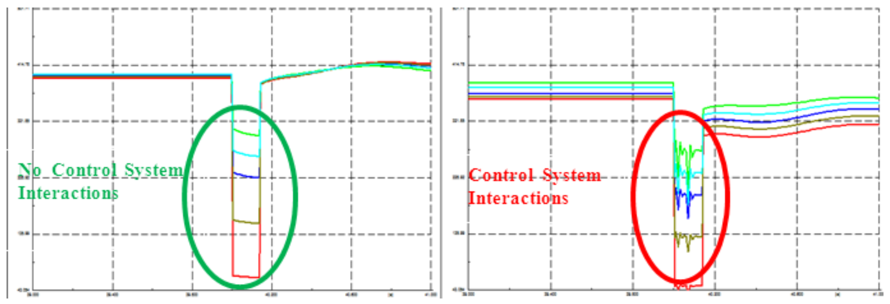


Figure 31 Control System Interaction

Impact on Operation

Some key areas that will see an increase in the connection of highly sophisticated control systems have been identified (as noted below). The interactions of these control systems need to be studied as soon as connection possibilities are perceived and at their early design stage:

- South East: connection of NEMO HVDC, Eleclink HVDC, and new SVCs, along with existing wind farm HVDC links;
- North Wales: large number of new wind farm connections in proximity of East West HVDC Interconnector, Western HVDC link, series capacitor and other new HVDC Links;
- East Coast: interaction between new multi-GW wind farms connected via VSC-HVDC;
- Scotland: new VSC HVDC connections in areas of low system strength.

Work in Progress and Key Findings

In case of South East, the studies show a greater need for control coordination between dynamic voltage control devices installed in this area and large VSC HVDC interconnectors (Eleclink and NEMO). The East Coast will also require similar treatment but at a later date based on the current FES.

In addition to National Grid studies, R&D work on interactions between series capacitors and wind turbine control systems has been initiated and results are expected by in early 2016.

The table below summarises the impact of each of the scenarios on the aspects associated with control system interaction.

Table 10 Control System Co-Ordination Requirements

Region	Gone Green	Slow Progression	Low Carbon Life	No Progression
South East	Greater need for co-ordination expected in 2018/19	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected until 2020/21	No additional mitigation requirement expected until 2021/22
North Wales	Potential for more extensive control co-ordination after 2016			
East Coast	Triggering events expected in 2019-2023	No additional mitigation requirement expected until 2024/25	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected before 2035/36

Mitigation

With the ever increasing numbers of grid connected users employing sophisticated control systems, there is an opportunity for the SO to coordinate the response of these devices to ensure economic and efficient operation. The initial step is the modelling, and without representative models it has proven impossible to perform any control coordination task. The use of Phasor Measurement Units (PMU) is recommended to assist the SO in validating the dynamic models with system parameters to enable optimal coordination of control systems on the network.

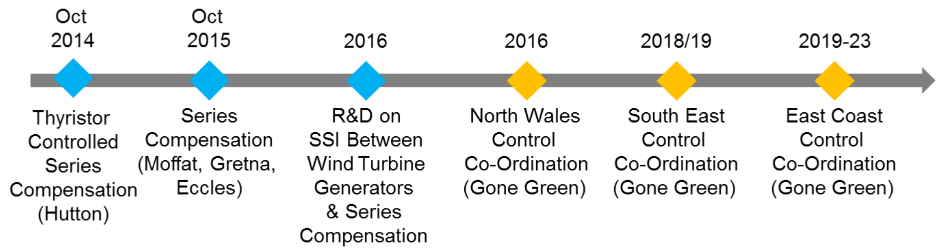


Figure 32 Control System Interaction Timeline

4.4.2 System Wide Controllers

With HVDC converters, series compensation, FACTs and various other control devices on the transmission network, it is important to ensure that such devices are used effectively and that they assist with maximum utilisation of transmission capacities, enhance overall system stability, reduce constraints, minimise losses and reduce control interaction. To achieve these objectives, the concept of System Wide Controllers (SWCs) is being developed within National Grid and this work is also being discussed with R&D organisations.

Impact on Operation

The development and application of new and advanced controllers and algorithms for SWCs on the GB transmission network can help avoid costly network reinforcements.

Work in Progress and Key Findings

Additional transmission circuits and other reinforcements are required to accommodate increased levels of renewable generation, and such a need has already been identified in ETYS. Further investigations and new study tools and software are therefore required to design suitable SWCs and to assess their suitability and benefit for system operation.

Mitigation

With more of the HVDC converters, series compensation, FACTs and various other control devices existing or foreseen to be installed on the GB transmission system – offshore, onshore and embedded – there appears to be a strong need not only to optimise the use of these devices but also to ensure their benefit to provide maximum transmission capacities across boundary circuits. The opportunity in the form of SWCs needs to be investigated, and it may require acquisition of more and faster network data, telecommunication means, new software and modelling tools, and development of suitable control strategies.

4.4.3 Interaction and Collective Recovery and Stability of Power Electronic Sources

In a system with high inertia the behaviour of the network contains inherent resilience against frequency instability, with largely linear relationships between machine controllers and transmission network behaviour.

Voltage characteristics in a high inertia system are similarly directly related to the dynamic automatic voltage controller characteristics of the machines connected, throughout all time phases of a system disturbance. A high inertia transmission system therefore provides two benefits to the design and planning of the system:

- Most aspects of individual generator design, simulation and testing can be conducted in a single machine environment with a reduced representation of the synchronous system that the generator is connected to;
- It is straightforward to identify the worst case disturbance conditions from the topology of the connected network and the effect any fault has on the transmission interface with the generation.

In a system where power electronics are the dominant component of the system strength, the above behaviour and approximations no longer hold, and new ways of studying system behaviour have to be employed in response to the rise in power electronic connected sources.

Impact on Operation

When large areas of the system become dominated by power electronic connected sources, the following aspects of system dynamic behaviour have to be considered:

- The voltage and frequency waveform and dynamic behaviour will be dictated by the collective relationships of power electronic controllers and cannot be guaranteed to be linear against all conditions, particularly those relating to unbalanced disturbance or system disturbances that place particular stresses upon the control systems of the technology concerned;
- During the period of any fault condition, owing to the characteristics of the non-synchronous technologies, there will be a limit to the extent to which performance beyond simply “riding through” the fault will be available;
- Where disturbances evolve rapidly, interaction between the characteristics of the transmission network components (which will respond inherently dynamically to the disturbance) and the power electronic control action (which will respond/reference to the system condition relative to its individual design) will occur, making such behaviour harder to predict and simulate;
- Where system disturbances are widespread, a collective behaviour of individual power electronic controllers and behaviours will be observed; under such disturbances, de-stabilising interactions and hunting of control action across the controllers of the different non-synchronous generation sources will need to be considered and control system calibration and risk of saturation will require simulation and associated design and validation;
- It will not be possible to robustly simplify generation technology design in such areas to a simplified system equivalent representation of the transmission system as it would not simulate control system behaviour in relation to system disturbance representatively.

Work in Progress and Key Findings

The level of power electronic device interaction and its effect on the wider system is not expected to become notable until at least such time that these sources become dominant within an area. The duration curves in section A.4 of Appendix A further illustrate the amount of time high NSG/Demand may be experienced in the future.

Mitigation

As outlined above, the effects between power electronics being non-linear and numerically complex in their modelling do not lend themselves to effective simulation or planning within the real time system operation and control environment. Preventative action to remove the undesirable circumstances associated with power electronic connected sources being dominant on the system would need to be taken to avoid the risks in the operational timeframe. This would result in the need to increase the levels of synchronous response by:

- Constraining on synchronous generation;
- Use of synchronous compensation devices available in the affected area;
- Restriction of the number of NSG sources connected in one area;
- Restriction of the period when these vulnerabilities exist.

4.4.4 Commutation Failure

The interaction between the AC network and HVDC links is one of major concern in hybrid AC/DC power systems. The significance of the interaction between the AC and the DC systems depends on the strength (short circuit level) of the AC system at the HVDC converter bus.

Commutation failure happens if the commutation of current from one CSC valve to another has not been completed before the commutating voltage reverses across the ongoing valve. This results in a short circuit across the valve group. AC system faults affect the commutation margin by voltage magnitude reduction, increased overlap due to higher DC current and phase angle shifts.

The above can be caused by AC voltage faults and disturbances, transformer inrush current, capacitor inrush current, harmonic pollution and/or instability, and system induced resonances.

Where the minimum short circuit level near the terminal of the HVDC link is already low, certain circuit outages can reduce it even further, thereby increasing the risk of commutation failure on the nearby CSC HVDC links.

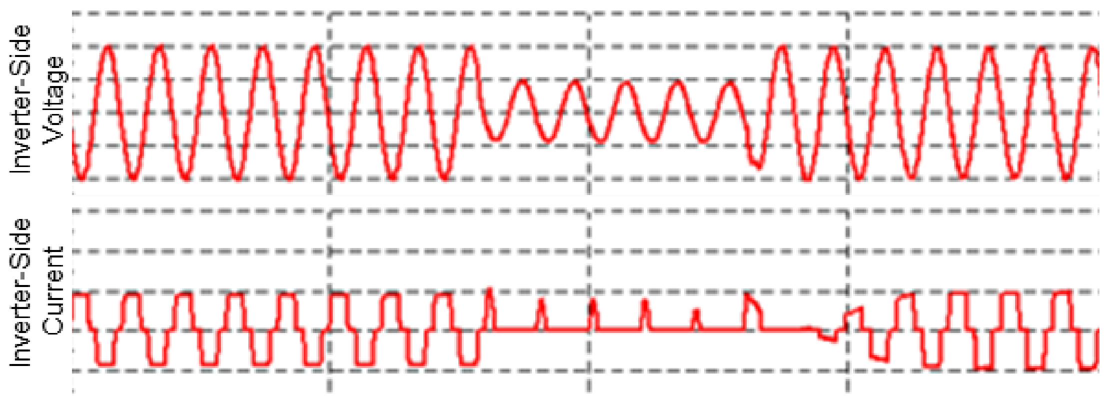


Figure 33 Commutation Failure

Only the HVDC links based on CSC technology are susceptible to commutation failure. The HVDC links that may be exposed and therefore assessed against this risk are: Moyle, Britned, cross-channel link Interconnexion France Angleterre (IFA) and the Western HVDC link. The East West HVDC Interconnector and the majority of future HVDC links are likely going to be based on the VSC technology and will not be affected by commutation failure.

Impact on Operation

Commutation failure brings temporary interruption of HVDC power, and in some cases might induce more serious problems and longer power curtailment. The consequences of commutation failure can be interruption of power transmission, stresses on the valve equipment, or triggering of more severe transients, such as system resonances.

Following voltage recovery, the link will de-block and resume power transfer; however the speed of voltage recovery again depends on the short circuit level of the AC system. HVDC manufacturers generally recommend the minimum short circuit level of 3 times the rating of the link, i.e. 6 GVA for a 2 GW link.

Minimum short circuit levels have been established at the design stage of current CSC HVDC links to ensure the avoidance of commutation failure.

Work in Progress and Key Findings

Studies have been carried out to estimate the minimum fault levels around the current HVDC links and to evaluate possible mitigation actions.

Studies suggest that when Hunterston power station is decommissioned, with very few synchronous machines on the Scottish network under certain circuit outages the short circuit level at the Northern terminal of the Western HVDC link may fall to around 3.3 GVA. This may impose an operational restriction on the level of power flow across the link during times when power across the link is flowing from England to Scotland. EU Network Code HVDC[13] in its current draft format also contains various requirements for CSC HVDC links with the aim to minimise the exposure to commutation failure risk.

[13]http://networkcodes.entsoe.eu/wp-content/uploads/2013/08/131107-NC_HVDC_-_for_public_consultation.pdf

Mitigation

Reactive power compensation is widely used to improve voltage stability in the steady state and the transient state of power systems. Some possible means of voltage regulation are the Synchronous Condenser (SC), the SVC and a Static Synchronous Compensator (STATCOM).

Using power-electronics-based compensators such as SVCs and STATCOMs increases the ability to maintain the converter bus voltage. However, these devices are not rotating machines so they do not increase the short-circuit level at the converter bus. The STATCOM provides both the necessary commutation voltage to the HVDC inverter and the reactive power compensation to the AC network during steady state and dynamic conditions.

On occasions when the transmission system is subjected to a level of stress exceeding the levels secured against as per the NETS SQSS and the Grid Code, it is possible that, to protect against asset damage and risks to personnel, the system will either wholly or partially “black out”. The probability of such black outs is extremely low and historically the GB transmission system has never been subject to a total system blackout. Nevertheless, these scenarios are possible and hence have to be considered.

There have been a number of occasions where limited regional blackouts have occurred due to extreme events, most notably in England and Wales during the hurricane of 1987 when the whole of SE Kent was blacked out for over 12 hours following a loss of transmission connection. There have also been 19 smaller incidents over the thirty two year period 1981 – 2013 during which areas of the England and Wales network have become disconnected. 16 of these incidents resulted in generation successfully islanding with the disconnected demand. Within Scotland, the incidence of regional network disconnection has been more frequent, owing to a more extreme weather context affecting a more distributed and less interconnected transmission system, the most recent events being those in April 2014 when a significant part of the demand in the Inverness area was disconnected under a 4 circuit disconnection condition.

In such situations as these, National Grid as the System Operator has a plan and a set of policies detailing the approach that would be taken towards restoration of the network under a black start scenario. Restoration services are currently contracted from an array of thermal plants technically capable of re-energising the system without the reliance on external power supplies. The guarantee that a structured approach to network restoration would be possible depends on the availability of these services.

Across the period of emergency restoration, the following network conditions pertain:

- Network strength is very low, typically dominated and defined by the black start provider;
- Frequency and voltage can be expected to vary beyond those limits as defined in Grid Code and NETSSQSS as networks are extended and demand block loads are allocated;
- The inertia, control and dynamics of the power island are dominated by the behaviour and the capabilities of the Black Start generator.

Impact on Operation

In the case of the Gone Green and Slow Progression scenarios in particular, but also regionally against the Low Carbon Life and No Progression scenarios, the generation mix is expected to be dominated by NSG. For such areas, there are several challenges associated with the availability of traditional restoration service provider availability. UK nuclear plants have not traditionally been able (technically or from a safety perspective) to support emergency restoration; CCGT and coal reliability for emergency restoration tends to be inversely proportional to the time since warmed, and the potential availability of even "cold" synchronous reserves is set to decline to a few modern plant units.

Current system restoration methods have been designed to deal with a total system black out rather than partial, regional black outs as those experienced in the past. As system strength and the number of restoration service providers based on well-known technologies decline, the restoration strategy must be adjusted. Otherwise, the re-starting of the system becomes dependent on a very small proportion of generation remote from the load leading to weaker power islands more prone to voltage deviation and a requirement for more reactive power support locally.

Work in Progress and Key Findings

The FES, Low Carbon Life in particular, project that several of the gas and coal fired units may be replaced or upgraded to reduce their emissions and meet various environmental targets. These upgraded units may, for example, include full or partial conversion to biomass-powered plants and the fitting of Carbon Capture and Storage (CCS) systems. From a technical point of view, any of the existing service providers would need to be re-tested after undergoing such significant conversions it is not guaranteed that they would be able to provide the same services, or to the same degree as before conversion.

Although the emergency restoration conditions described above present a challenging operational environment for generators participating in emergency system restoration, the parameters and capabilities of new technologies, such as VSC HVDC links (either in the form of interconnectors to other countries or wind turbine generator connections) and many of the new thermal units expected to connect or be upgraded in the future, are considered to be suitable for emergency restoration service provision, and therefore could form the portfolio of new service providers to replace existing ones as they reach the end of their operational lifetime. The technical aspects of the service from these new providers are still to be defined, but in the case of VSC HVDC links the work on this has already begun.

The main questions to be answered as part of a more detailed investigation in future are:

- Can NSG and VSC energise a dead network; if so, what are the criteria for this;
- What are the dynamic voltage containment needs for a network being re-energised from remote points where thermal services may remain;
- What is the minimum system strength that a network island must have before a hybrid synchronous generation and NSG re-energisation solution is possible;
- How a stable dynamically collective source islanding be ensured.

Mitigation

EU is driving the creation of an "Emergency and Restoration Code"[14]. In addition to the wish to standardise approaches to emergency restoration.

Another objective of this code is to complement the Cooperation of Electricity System Operators (CORESO) security assessment role, with clarity of the ability of various power islands developed as part of an emergency restorations scenario to re-energise external grids. In UK the VSC HVDC link between Ireland and Mersey could form part of a black start approach, as could new Eleclink, NEMO, FAB link and IFA2 links into continental Europe.

The drafting team is currently being assembled; expected milestones are:

- A first Table of Content is drafted in April 2014;
- 3 Public Workshops in July 2014, October 2014 and January 2015;
- Public consultation to take place in October - November 2014;
- Final submission to the Agency for the Cooperation of Energy Regulators (ACER) is expected by end of Q1 2015.

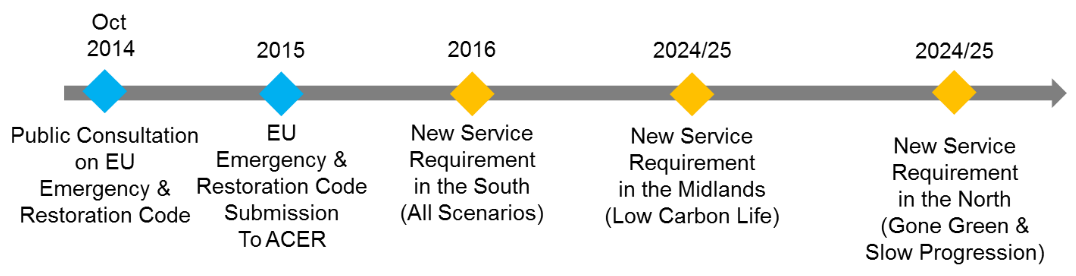


Figure 34 *Emergency Restoration Timeline*

New nuclear generators to be built in UK in future years are expected to have the ability to derive power islands from their site supplies, the so called "trip to house load". This is a technique used extensively outside of the UK to provide resilience. This capability is further complemented with all new generation required to support power islands equal or greater than 55% of the machine rated output. Wind turbine generators are in principle capable of still better load matching, subject to weather conditions.

Going forward, in addition to a potential new portfolio of VSC HVDC and advanced thermal plants being able to provide support, rather than continuing to use the current approach, a multi-tier system preservation and restoration methodology could potentially be applied:

Normal Operation:

- Define precautionary operational states such that the system is only susceptible to very low probability events (e.g. storm conditions on 5 December 2013). Cost/benefit analysis can be applied to evaluate the benefits of securing against such low probability events or moving to the “brown-out” scenario described below.

"Brown-Out" Containment for Extreme System Events:

- This could involve the use of existing Low Frequency Demand Disconnection (LFDD) and the development of a tiered High Frequency Generation Disconnection (HFGD) provision, together with Low Voltage Demand Disconnection (LVDD) and High Voltage Demand Disconnection (HVDD) provision, all complemented where possible with demand side and storage services;

[14] http://www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/System-operation.aspx

- The above techniques should also (where feasible) be complemented by a transmission-level automation action carrying out “triage” by e.g. disconnecting a region experiencing voltage collapse before its effects compromise a larger system area, disconnecting an area of high regional frequency imbalance, or identifying route instabilities on the network and disconnecting those specifically;
- Within credible load islands, perform additional multi-machine assessment of the aggregate behaviour of the generation responding to islanding. Great care has to be taken with regards to the settings and controllers driving these actions;
- In addition to ensuring the system "brown-outs" rather than "black-outs", there is a need to define how the operator could grow the browned-out islands. In principle this is already in place, but the number of islands created may change using this approach. Equally, there is a question whether after the system has been islanded under these various defence measures, do those measures remain active during the growing of power islands or are they switched out.

Black start of the de-energised network

- In this case, more focus must be given to voltage control;
- The optimal size that the power island must reach before NSG is re-connected needs to be considered;
- Using the ability of the nuclear fleet to "trip to house load" could be implemented. A three-level approach is used in France:
  - Generator and system conditions are suitable for the nuclear plant to form larger power island;
  - Generator conditions are such that the nuclear plant is safe, but not ready/able to enlarge a power island;
  - Generator conditions dictate that the nuclear plant needs grid supply back as soon as possible.

The results and potential new approaches will be further studied and assessed in collaboration with Market Operation. In the meanwhile, National Grid will continue to explore the potential and requirements for restoration services from new providers, such as HVDC sources and synchronous generators based on new technologies (e.g. biomass units and units fitted with CCS).

DSOs role is expected to be active distribution network operation with the aim to aid technically and economically optimal overall electricity system operation. This would also include the facilitation of more active demand side participation in energy balancing and network constraint management, either from commercial customers or domestic customers via smart meters and enabled domestic appliances and embedded generation units.

The scope of the DSO role, as well as the technical, commercial and regulatory arrangements is currently being discussed both at a European level and nationally. The most notable of these fora is the Department of Energy and Climate Change (DECC) and Ofgem Smart Grid Forum[15]. Work Stream 7 in particular has been set up to undertake a detailed analysis of the future power system, focusing on the distribution networks.

Although the DSO role as a whole is still in very early days of development, certain aspects of this role are already being delivered by smaller initiatives, such as Active Network Management[16] (ANM) schemes currently operating in several regions in Scotland and the Midlands, but expected to rapidly evolve in other regions as the amount of embedded generation connections continue to increase. The principle of the ANM schemes is that a new generator customer can be given access to the system (at a distribution level) in locations with high density of existing connections and new connection applications ahead of network reinforcement to the required capacity. The customer should agree to automatically reduce their output during times when the power flows on the local network are close to the maximum operational capability of the network at that time, until the network reinforcements required to support full output are complete. ANM currently only applies to generation units, but could be similarly applied to loads in the future, thereby further moving towards a DSO role.

DSOs in their full capacity have the potential to be able to grow the scope and volume of demand side response (DSR) and services and alleviate some of the constraints and challenges that would otherwise have to be solved by additional investment at a transmission level.

The evolution of these active DSOs as described in Figure 34 is not expected at least until the end of the current DNO price control RIIO-ED1 that ends in March 2023. Until then, many of these solutions are expected to be delivered in a similar way as they are currently, unless otherwise mandated by any of the network codes.

[15] https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-and-ofgem-smart-grid-forum
[16] http://www.smartergridsolutions.com/insights/active-network-management.aspx

The System Operability Framework is an ambitious and far-reaching framework ensuring holistic assessment of the GB power system in response to the Future Energy Scenarios. The analysis includes an extensive assessment of the resources, system operation constraints and new services and capabilities required to facilitate or to accommodate the various changes in system dynamics.

The shift from a generation mix dominated by synchronous generators to one dominated by NSG brings significant changes to the way the SO needs to operate the system, taking into account a wider range of parameters. SOF aims to ensure such parameters are studied in detail and, if the variance seen as a result of changes in the generation mix is perceived to be capable of impeding system operability, potential mitigating measures are identified, as summarised below.

Summary of Findings

The figure below summarises the earliest requirement for the enablers for further NSG growth on the GB system as described throughout this report.

The expected total transmission-connected NSG capacity[17] for each of the scenarios is shown in the background. This not only illustrates the scale of the changes that the GB system must undergo in the coming years, but also highlights the potential for developing and making available new or enhanced capabilities and services from new and existing NSG sources, that could provide valuable system operability support, provided that the enablers are put in place either by means of support from existing and future synchronous and NSG, asset investment, demand side services, or a combination of the above.

A number of new approaches and recommendations have been highlighted throughout the document. The main items and the operability aspects that they could benefit are shown in Figure 36. Other key points to highlight are:

- The Rapid Frequency Response delivery from NSGs which are capable of providing fast response may require new services to attract potential providers. The frequency control, and high rate of change of frequency require new services to avoid carrying large volume of response.
- The contribution of NSG to system stability is currently very limited. as a number requirements applicable to synchronous power plants are not yet provided/maintained by NSG. SOF has recommended a number of requirements such as power oscillation damping and Fault Ride Through capability for smaller units that can be delivered by NSG.
- Improving the study capability is one of the key recommendations of SOF in many topics. This includes the use of new tools such as advanced monitoring using Phasor Measurement Units (PMU), new modelling tools for transmission and distribution interface issues to ensure better assessment of the impact of change in energy landscape in the whole system.

[17]Including interconnectors

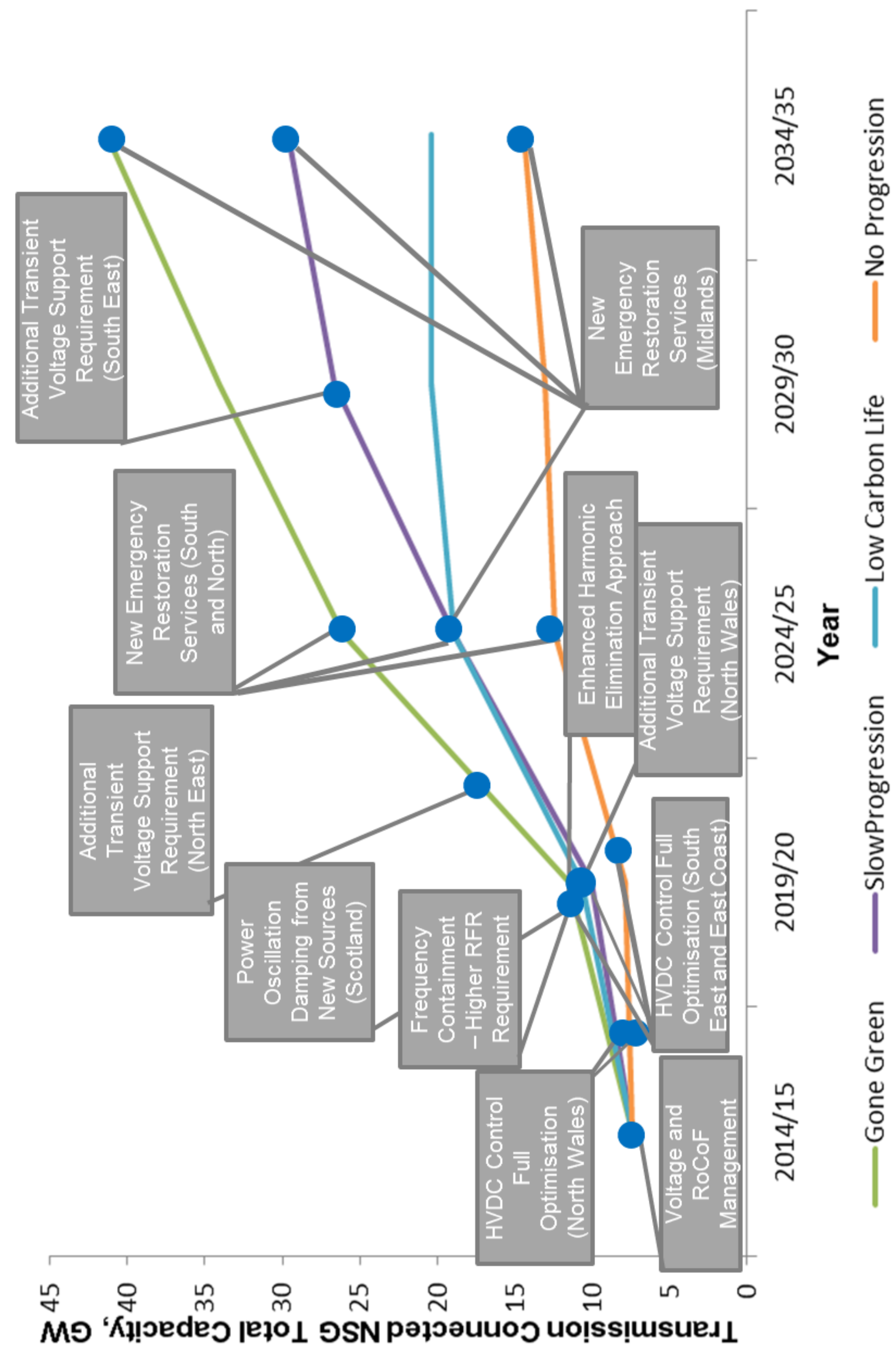


Figure 35 SOF Requirements Timeline

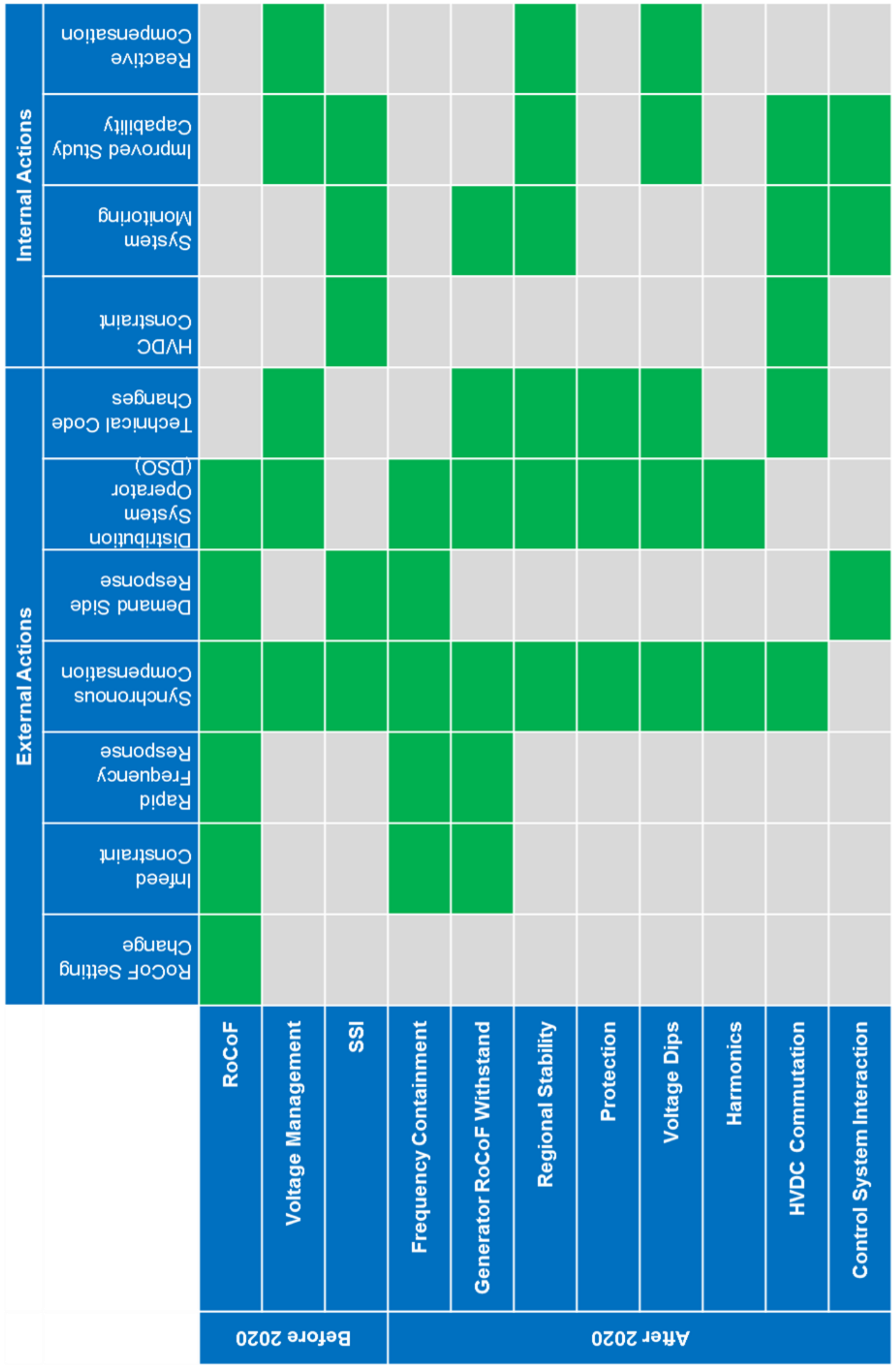


Figure 36 System Operability Support Opportunities

Way Forward

This is the first edition of the GB System Operability Framework (SOF). We encourage you to provide feedback and comments on this document. We have planned a range of stakeholder engagements in order to better discuss the SOF, and understand how it can be further developed in the future.

We invite you to participate in the 2014 SOF Consultation process. In addition, please provide your feedbacks on all aspects of this document via transmission.sof@nationalgrid.com

SOF 2014 Consultation

The Network Strategy team is running a question-based consultation to get industry feedback on SOF that will help it develop the quality of the analysis, and findings reported in the first version of SOF, in ways that will make it most useful to the energy industry.

We aim to consult our stakeholders on the following key areas of SOF:

- methodology and approach used in SOF;
- interactions with industry codes and standards;
- cross-sector topics of SOF;
- solution delivery and whether new commercial services are required.

A summary of SOF, incorporating the comments and responses to the SOF consultation, is expected to be published as part of National Grid's Electricity Ten Year Statement (ETYS) in November 2014.

List of Acronyms

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ANM	Active Network Management
CCGT	Combined Cycle Gas Turbine
CORESO	Coordination of Electricity System Operators
CSC	Current Source Converter
DC	Direct Current
DCC	Demand Connection Code
DECC	Department for Energy and Climate Change
DFIG	Doubly Fed Induction Generator
DNO	Distribution Network Owner
DPC	Distribution Planning Code
DSO	Distribution System Operator
DSR	Demand Side Response
EFCC	Enhanced Frequency Control Capability
ENTSO-E	European Network for Transmission System Operators—Electricity
ERFR	Enhanced Rapid Frequency Response
ETYS	Electricity Ten Year Statement
FACTS	Flexible AC Transmission System
FES	Future Energy Scenarios
FRT	Fault Ride Through
GSP	Grid Supply Point
HCC	HVDC Connection Code
HFGD	High Frequency Generation Disconnection
HVDC	High Voltage Direct Current
HVDD	High Voltage Demand Disconnection
IFA	Interconnexion France-Aleterre
LFDD	Low Frequency Demand Disconnection
LVDD	Low Voltage Demand Disconnection
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standard
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NSG	Non-Synchronous Generation
PMU	Phasor Measurement Unit
POD	Power Oscillation Damping
PV	Photovoltaic
QB	Quadrature Booster
R&D	Research & Development
RfG	Requirements for Generators
RoCoF	Rate of Change of Frequency
SC	Synchronous Condenser
SESG	South East Smart Grid
SHE	Scottish Hydro Electric (Transmission)
SO	System Operator
SOF	System Operability Framework
SPT	Scottish Power Transmission
SSCI	Sub-Synchronous Control Interactions
SSR	Sub-Synchronous Resonance
SSTI	Sub-Synchronous Torsional Interactions
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWC	System Wide Controller
TCSC	Thyristor Controlled Series Capacitor
TEC	Transmission Entry Capacity
TO	Transmission Owner
UIF	Unit Interaction Factor
VSC	Voltage Source Converter

Glossary

Alternating Current (AC)	Electric power transmission in which the voltage varies in a sinusoidal fashion, resulting in a current flow that periodically reverses direction. AC is presently the most common form of electricity transmission and distribution, since it allows the voltage level to be raised or lowered using a transformer.
Automatic Voltage Regulator (AVR)	A device used to control the output voltage a generator to be equal to a pre-defined set point, both in steady-state and transiently (response speeds are 5 -20 milliseconds).
Capacitor	A device that stores energy in its electric field. Shunt capacitors are used as reactive power sources in reactive power compensation; series capacitors reduce the impedance of a circuit.
Carbon Capture and Storage (CCS)	The process of trapping carbon dioxide produced by burning fossil fuels or other chemical or biological processes and storing it in such a way that it is unable to affect the atmosphere.
Cascading Loss	The uncontrolled, successive loss of transmission elements as a result of a fault or an incident.
Combined Cycle Gas Turbine (CCGT)	A type of thermal generation that uses a two stage process. Natural gas is fed into a jet engine that then drives an electrical generator. The exhaust gases from this process are then used to drive a secondary set of turbines and in turn, a second electrical generator.
Commutation	The process of turning off one valve and turning on another in an HVDC converter.
Contracted Generation	A term used to reference any generator that has entered into a contract to connect to the National Electricity Transmission System (NETS) on a given date whilst having a Transmission Entry Capacity (TEC) figure as a requirement of said contract.
Cost Benefit Analysis (CBA)	A method of assessing the benefits of a given project in comparison to the costs. This tool can help provide a comparative base for all projects considered.
Current Source Converter (CSC)	A type of High Voltage Direct Current (HVDC) converter; also referred to as Line Commutated Converter. This type of converter usually employs thyristors as the switching devices .These can only be turned on, and not off, by a control action. The commutation process relies on the line voltage of the AC system the converter is connected to and the direction of the DC current cannot be reversed.
Direct Current (DC)	The transmission of power using continuous voltage and current as opposed to AC. DC is commonly used for point-to-point long distance and/or subsea connections. DC offers various advantages over AC transmission, but requires the use of costly power electronic converters at each end to change the voltage level and convert it to/from AC.
Double Circuit Overhead Line	In the case of the onshore transmission system, this is a transmission line that consists of two circuits sharing the same towers for at least one span (line section between two adjacent towers) in Scottish Hydro-Electric Transmission (SHE Transmission) system or National Grid Electricity Transmission (NGET) transmission system or at least 2 miles in Scottish Power Transmission (SPT) system. In the case of an offshore transmission system, this is a transmission line that consists of two circuits sharing the same tower for at least one span.
Embedded Generation	A term used to refer to any generation unit that is not directly connected to the NETS. This can typically include solar panels on domestic properties along with combined heat and power plants that may supply industrial facilities.
Energy	The total power used over a period of time. Electrical energy is usually expressed in kilowatt-hours (kWh) or Megawatt-hours (MWh).

European Network for Transmission System Operators (ENTSO-E)	ENTSO-E is a Europe-wide organisation that is responsible for representing all Electricity Transmission System Operators and others connecting to their network. It addresses all their technical and market issues as well as coordinating planning and operations across Europe.
External System	A transmission or distribution system located outside the NETSO area that is electrically connected to the onshore transmission system by an external interconnection.
Fault	An unintentional short circuit in a system.
Flexible AC Transmission System (FACTS) Device	A FACTS Device is a term used to describe any power system device based on power electronic systems and converters. Examples of such devices are Static Var Compensator (SVC), Static Synchronous Compensator (STATCOM) and Thyristor Controlled Series Compensator (TCSC).
Frequency Containment	The ability to arrest a very rapid frequency fall (following a fault or other severe condition) before it reaches the statutory limit of 49.5Hz.
Generating Unit	An onshore generating unit or an offshore generating unit.
Grid Code	A document specifying the technical requirements for the connection to, and the use of the NETS. Compliance with the Grid Code is a requirement under the Connection and Use of System Code.
Grid Supply Point (GSP)	A point of supply from the GB transmission system to a distribution network or transmission connected load. Typically only large industrial loads are connected directly to the transmission system.
Harmonics	Integer multiples of the fundamental system frequency, i.e. for 50Hz system frequency the 2nd harmonic has a 100Hz frequency; 3rd harmonic has 150Hz frequency, etc. Harmonic content in a voltage waveform distorts a perfect waveform and affects power quality.
High Voltage Direct Current (HVDC) Converter	Any apparatus used as part of the National Electricity Transmission System to convert AC to DC electricity, or vice-versa.
Infeed	Power supplied to the system.
Installed Capacity	In this report this term is used with the same meaning as Transmission Entry Capacity (TEC).
Interconnection	In this report the term refers to external interconnection – the apparatus for the transmission of electricity between the onshore system and an external system (e.g. a power system in another country) in either direction .
Load	The amount of electric power delivered or required at any point of the system (the power output of the system, or demand).
National Electricity Transmission System (NETS)	The National Electricity Transmission System comprises the onshore and offshore transmission systems in England, Wales and Scotland.
National Electricity Transmission System Operator (NETSO)	National Grid acts as the NETSO for the whole of GB whilst only owning the transmission assets in England and Wales. In Scotland, transmission assets are owned by SHE Transmission in the North and SPT in the South.
National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)	A set of standards used in the planning and operation of the NETS in GB that is applicable to both onshore and offshore transmission systems.
National Peak Demand	A point at which electricity generation is at its highest in order to meet the winter peak demand (often during the coldest winter days).

Net Demand	Demand as seen at the GSP: actual power demand minus embedded generation output power.
Non-Synchronous Generators (NSG)	Non-synchronous generators either produce DC power (like solar PV cells) or their output voltage waveform phase and frequency is different from the grid frequency, therefore DC converters are needed to connect these generators to the grid.
NSG/Demand	The power output of non-synchronous (NSG) sources (i.e. wind and solar generators and interconnectors if importing power) at any given time as a fraction of the net demand at that time.
Offshore	Wholly or partially in offshore waters.
Offshore Generating Unit	Any apparatus that produces electricity, including synchronous offshore generating units and non-synchronous offshore generating units, and is located in offshore waters.
Onshore	Wholly on land.
Onshore Generating Unit	Any apparatus that produces electricity, including synchronous onshore generating units and non-synchronous generating units, and is located onshore.
Onshore transmission Licensees	NGET, SPT and SHE Transmission.
Onshore Transmission System	The system consisting (wholly or mainly) of high voltage electricity lines owned or operated by onshore transmission licensees and used for the transmission of electricity: ■ From a power station to a substation; ■ Between power stations; ■ Between substations; ■ To or from offshore transmission systems; ■ To or from any external interconnections. This includes any plant, apparatus and meters owned or operated by the transmission licensees within GB that are in connection with the transmission of electricity.
Oscillations	Cyclic variations in voltage, current or power flow.
Phase	A term used in power systems to describe the three conductors used to efficiently generate and transmit power; each of the conductors is referred to as phase.
Power Factor	The ratio of real (active) power (MW) to complex power (MVA). For loads, the power factor is the cosine of the angle between the voltage and current. A load with a power factor of 1 only draws real power.
Rate of Change of Frequency (RoCoF)	A term meaning the ratio of change in system frequency and a given time period (∆frequency/∆time).
Reactive Power	Reactive power is a concept used by engineers to describe the background energy movement in an AC system arising from the production of electric and magnetic fields. These fields store energy that changes through each AC cycle. Devices that store energy by virtue of a magnetic field produced by a flow of current (reactors) are said to absorb reactive power; those that store energy by virtue of electric fields (capacitors) are said to generate reactive power, both of these devices are referred to as reactive power compensation devices.
Reactor	A device that stores energy in its magnetic field. A shunt reactor absorbs reactive power and is used in reactive power compensation; a series reactor can be used to protect against excessively large currents in fault conditions.

Real Power	The term (sometimes also referred to as “active power”) is used to describe the provision of the useful energy to a load. In an AC system real power is accompanied by reactive power for any power factor other than 1.
Rotor Angle Stability	This is the ability of synchronous machines to remain stable and maintain synchronism with the system (magnetic field of the synchronous generator rotating in synchronism with the system it connects with).
Short Circuit	A low impedance path; in a power system it is used with the same meaning as a fault.
Short Circuit Level	Short circuit current or fault current is the highest current encountered in a power system, under fault conditions. Maximum short circuit level is calculated in order to specify the highest stress conditions that transmission assets have to withstand during a fault. Minimum short circuit level is calculated to specify the minimum signal that protection devices need to detect in order to be able to detect a fault.
Static Synchronous Compensator (STATCOM)	A device used in power systems for reactive power compensation that can act both supply and absorb reactive power. STATCOMs and SVCs have similar functions, however STATCOMS have enhanced capabilities and therefore more diverse applications.
Static VAr Compensator (SVC)	A combination of shunt reactors and shunt capacitors that are used to provide reactive power compensation.
Sub-Synchronous Resonance	A condition in a power system where the electric network exchanges energy with a turbine/generator at one or more of the natural frequencies of the combined system. The frequency of the energy exchange is below the synchronous frequency of the system.
Summer Minimum Demand	The point at which electricity generation is at its lowest due to low demand. This is often attributed to longer daylight hours, lack of lighting demand and reduced heating demand.
Synchronous Generators	Synchronous generators produce voltage waveform that is synchronised with the rotor synchronous speed and that has the same frequency as the system they are connected to (50Hz in GB). These generators are usually directly connected to the AC power system without the use of converters.
System Constraint	A limitation on the use of the system due to the lack of transmission capacity or other system conditions.
System Frequency	The rate at which the voltage waveform repeats itself (50Hz in GB). At 50Hz power infeed and load on the system are equal; if the infeed becomes higher, the frequency (or system speed) increases; if the load becomes higher than total infeed, the frequency decreases.
System Inertia	The property of the system that resists changes. This is provided largely by the rotating synchronous generator inertia that is a function of the rotor mass, diameter and speed of rotation.
System Operability	The ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably.
System Stability	System stability refers to the ability to maintain equilibrium during normal operation and the ability to re-gain equilibrium following a fault or other incident. It can be further divided into voltage, frequency and rotor angle stability. With reduced power demand and a tendency for higher system voltages during the summer months, fewer generators will operate and those that do run could do so at a reduced power factor output. This condition has

	a tendency to reduce the dynamic stability of the NETS. Network stability analysis is therefore usually performed for the summer minimum demand condition as this presents the limiting factors, but other conditions may be studied if necessary.
Thermal Plant	A power plant where steam is used to drive a steam turbine.
Transient Fault	A term used to describe a temporary fault on the network that will often clear before the Delayed Auto Reclose system operates.
Transmission Capacity	The ability of a network to transmit electricity.
Transmission Circuit	This is either an onshore or an offshore transmission circuit that is either an overhead line or a cable.
Transmission Entry Capacity (TEC)	The maximum amount of active power deliverable by a power station at its grid entry point (that can be onshore and offshore). This will be the maximum power deliverable simultaneously by all of the generating units that connect to the grid entry point, minus auxiliary loads.
Transmission Owners	A collective term used to describe the three transmission asset owners within GB, namely National Grid Electricity Transmission (NGET), Scottish Hydro-Electric Transmission Limited (SHE Transmission) and Scottish Power Transmission Limited (SPT).
UK Future Energy Scenarios (FES)	The annual document that describes the range of scenarios used by NGET to provide a plausible and credible projection for the future of UK Energy.
Voltage Source Converter (VSC)	A converter that employs switching devices that can be both turned on and off by a control action, such as Insulated Gate Bipolar Transistors. In these converters the DC voltage polarity is fixed and the direction of the DC current can be reversed.
Voltage Stability	The ability of a power system to maintain voltage within operational limits or to recover after a fault, avoiding voltage collapse.
Winter Peak Demand	The estimated unrestricted winter peak demand (active and reactive power) on the NETS for the average cold spell condition. This presents the demand to be met by large, medium and small power stations (transmission connected or embedded) and by electricity imported onto the onshore transmission system from external interconnections.

The RIIO regulatory regime allows National Grid and the other GB network licensees to access various allowances to be used for network innovation. For 2014, National Gris has submitted two initial NIC project proposals for consideration by Ofgem. They have both passed the screening stage and are currently awaiting a decision by Ofgem following detailed proposal submission in July 2014. These projects are described in more detail below.

South East Smart Grid (SESG)

According to recent analysis[18], doubling the size of interconnection capacity could result in £1bn per annum total savings on GB consumers' electricity bills. It is expected that more than half of this saving is a result of the new interconnectors built in the South East of the network. In this region, FES forecasts a large volume of solar PV, onshore and offshore wind power generation and change in demand profile due to the change in the consumption pattern. At present, managing the network around the South East is a major challenge for the system operator, especially during periods of high power flow across the existing interconnectors. At low transfer periods, containing the system voltage within safety limits requires significant constraint cost and capital expenditure. This profile makes operability very challenging, and uneconomical in the long term.

By the time the new interconnectors are expected to connect to the GB system, the transmission network capability will not allow unrestricted flow across the interconnectors. There will be need for network reinforcement in the form of building a new transmission line at an estimated cost of over £500m and with a completion date no earlier than 2025. Otherwise, to operate the system securely it is required to either delay the connection date of interconnectors, or limit the power flow across them, both significantly affecting the benefit they bring to the GB consumers.

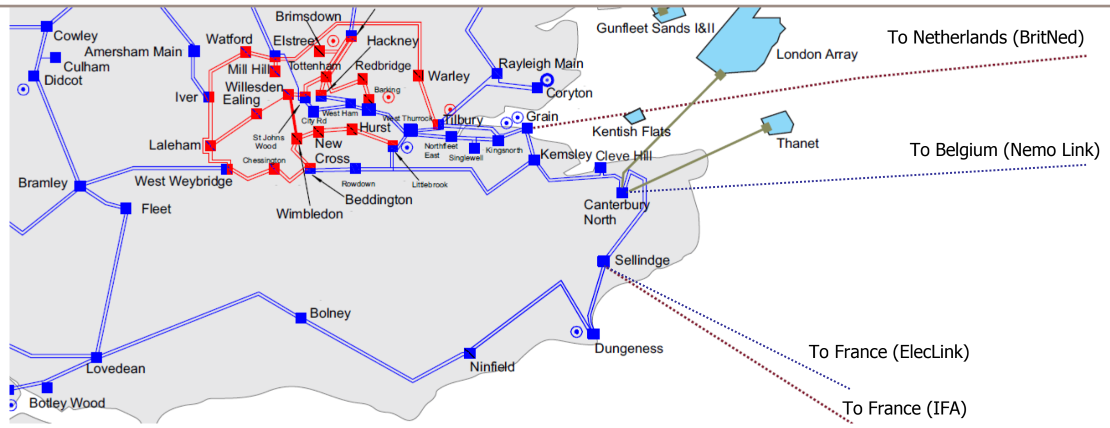


Figure A1 South East Area Transmission Network

The main aim of SESG project is to develop and demonstrate an innovative control scheme that changes the South East area into a smart grid and uses technologies such as demand side response (DSR) and energy storage to provide the transmission capacity the system requires by utilising the available distribution and transmission network resources, and increase the competition, resulting in potential £500m savings for the GB consumers.

[18] http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/

Enhanced Frequency Control Capability (EFCC)

The objective of this project is to develop and demonstrate an innovative new tool that will measure the RoCoF at a regional level and then enable the initiation of a proportionate, very fast response.

This tool will then be used to demonstrate rapid response from new technologies and resources:

- Demand side response (DSR);
- HVDC links;
- Solar PV;
- Energy Storage;
- Wind turbine generators.

Additionally, new (non-rapid) response from large-scale thermal power stations will be explored.

Through these demonstrations this project will show how the use of such resources, in an optimised way, can reduce the overall response requirement for the grid. A key deliverable will then be the development of new commercial balancing services.

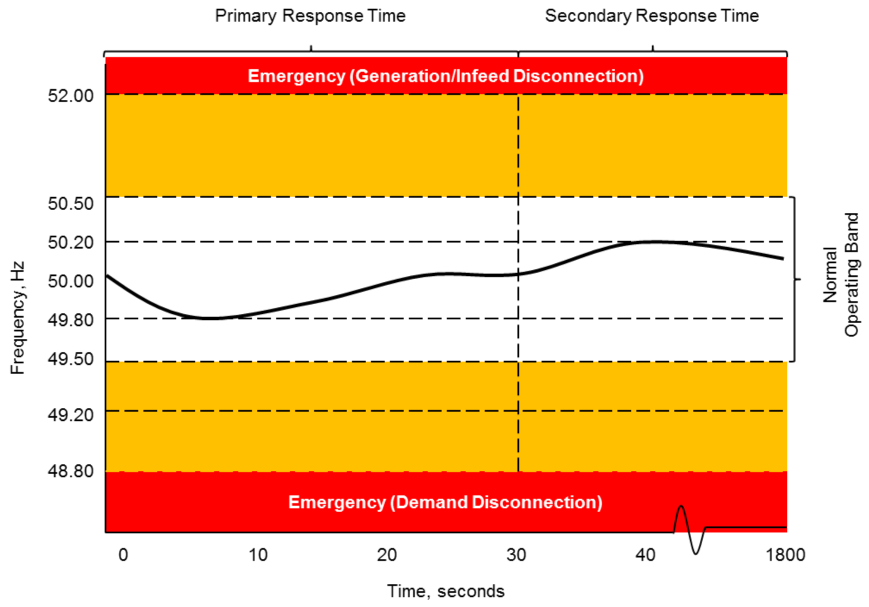


Figure A2 GB System Frequency Limits

Through reducing the level of frequency response required to manage system frequency, the successful development and implementation of this project may result in a total end consumer saving of £150m-£200m per annum.

This project is expected to run from April 2015 until March 2018.

Other Innovation Projects

Apart from the two NIC projects described above, there are many more smaller innovation projects covering all aspects of transmission and distribution network assets and system operation.

In the field of electricity system operation alone there are currently over 130 projects between all network licensees that have received NIA funding[19]. The main areas these projects are focusing are:

- New ways of using existing assets and enhancing their capabilities;
- HVDC assets and operation;
- Demand side response services:
- Developments in protection and control;
- Energy storage;
- Dynamic circuit ratings;
- Wide area system monitoring.

The following figures illustrate the Rate of Change Of Frequency (RoCoF) that the system would experience following the loss of the largest infeed present on the system in each of the years studied.

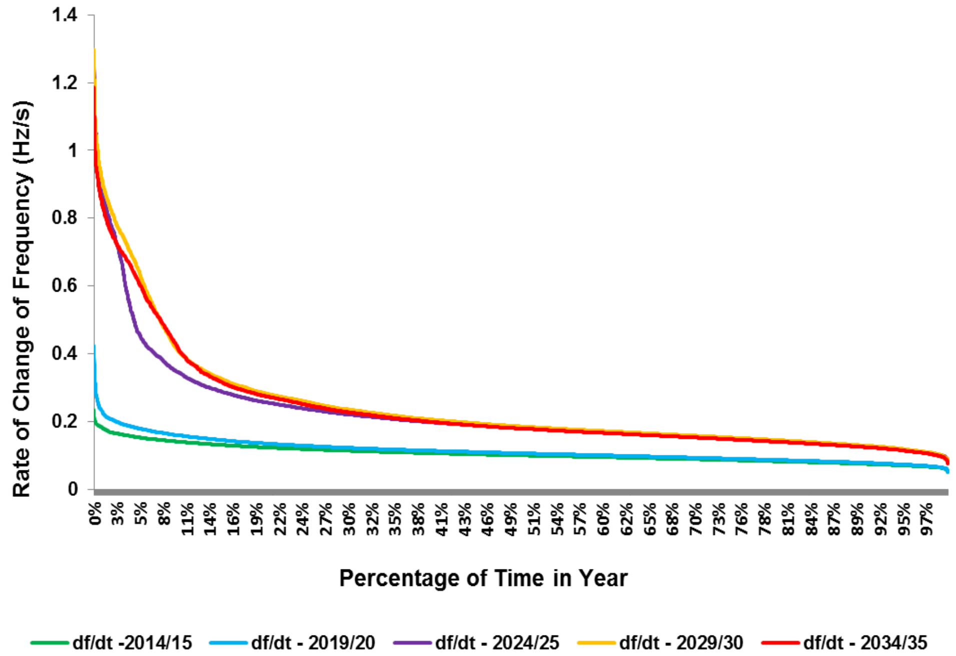


Figure B1 RoCoF - Gone Green

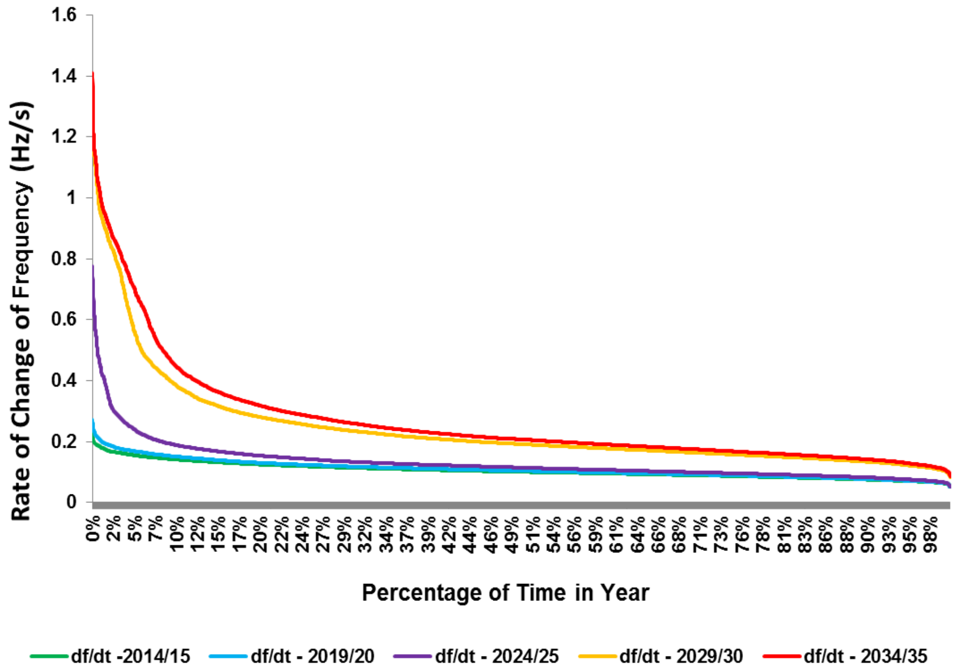


Figure B2 RoCoF - Slow Progression

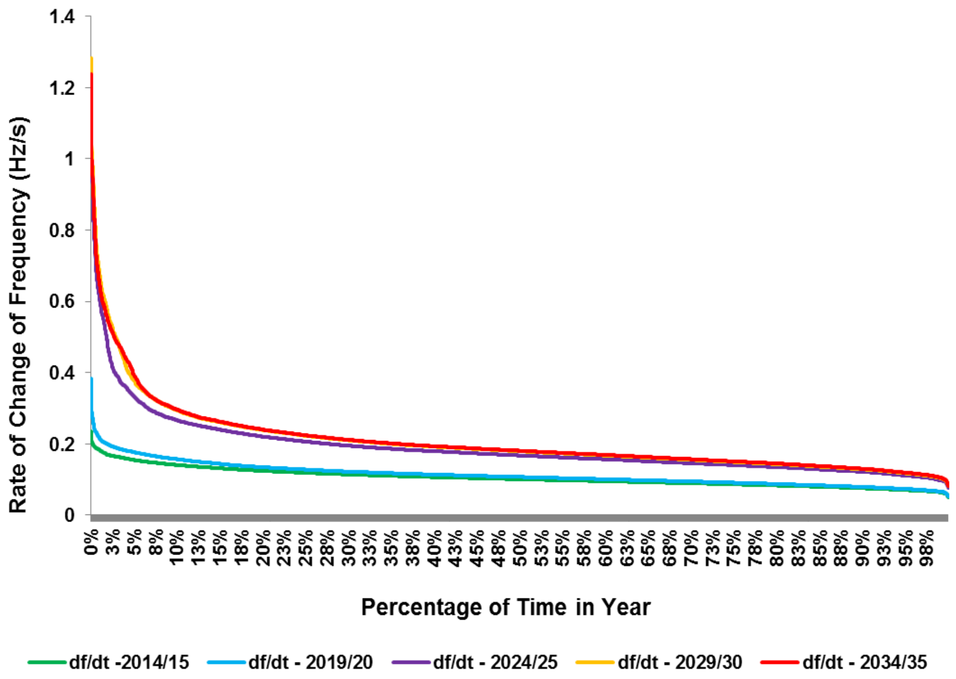


Figure B3 RoCoF - Low Carbon Life

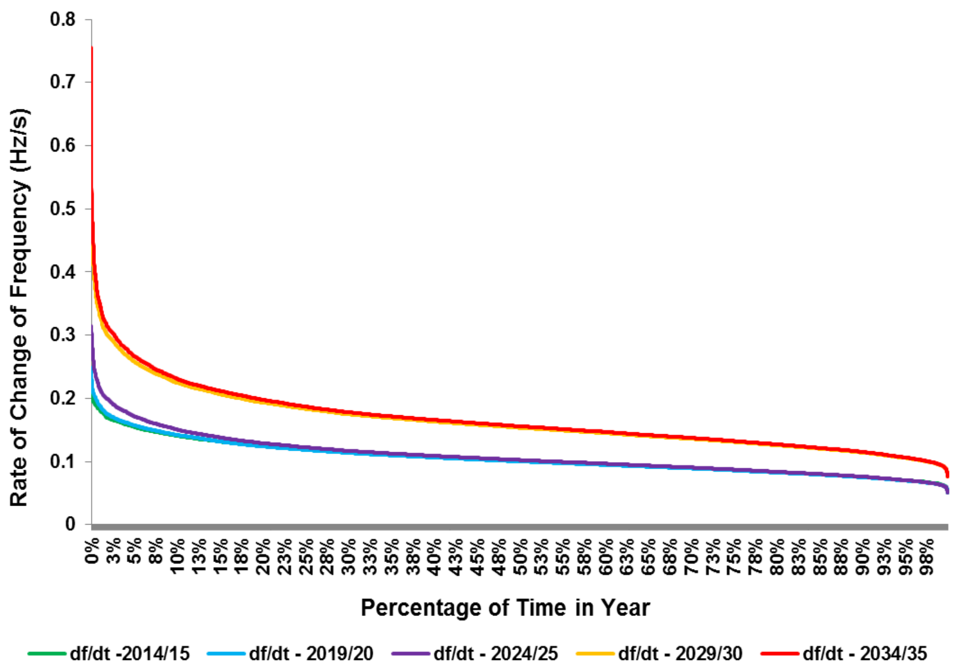


Figure B4 RoCoF - No Progression

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