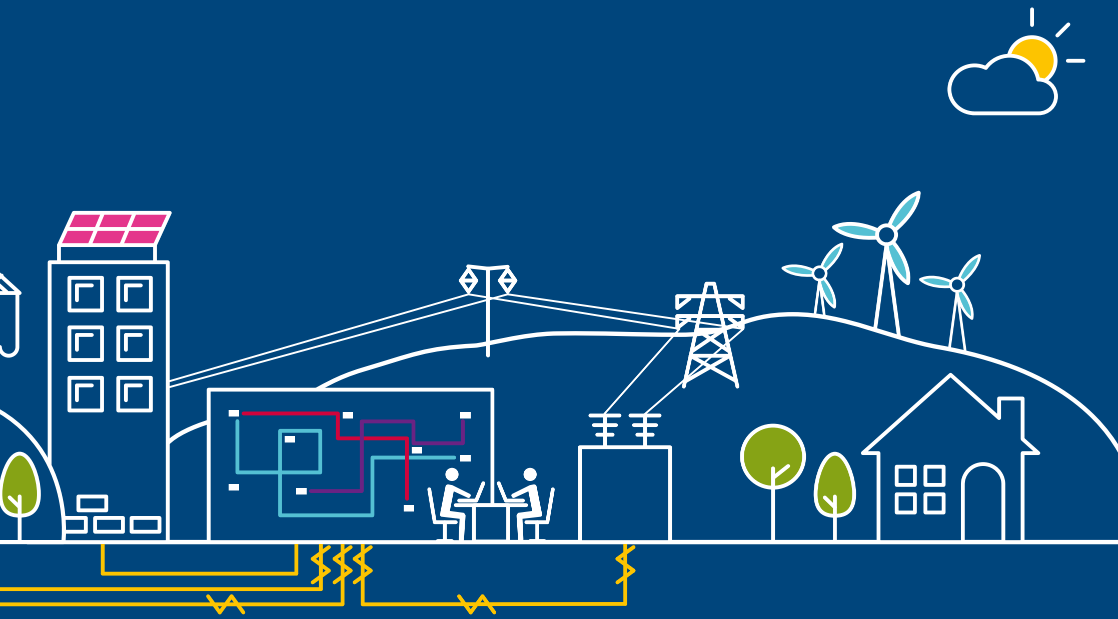
System Operability Framework 2015

UK electricity transmission



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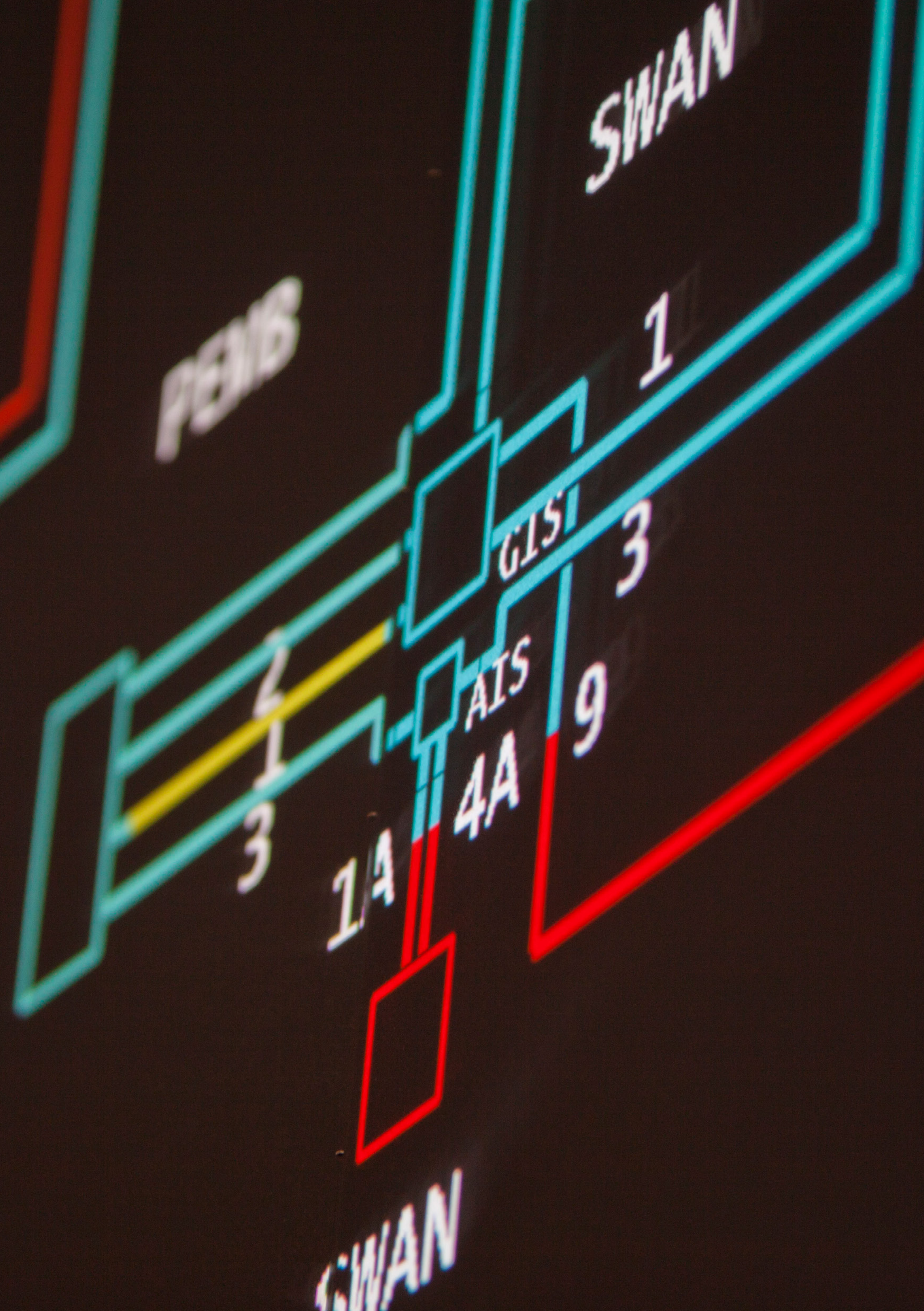
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Welcome to the 2015 System Operability Framework

This publication is part of the annual electricity transmission planning cycle which describes the future needs of the transmission network. The SOF is the latest of our suite of 'Future of Energy' documents which also includes: the Future Energy Scenarios (FES), Electricity Ten Year Statement (ETYS), Gas Ten Year Statement (GTYS), Winter Outlook Report and Summer Outlook Report.

When we look to the future, we use our Future Energy Scenarios to establish the network development needs. We developed the FES based on our stakeholders' views of the future energy landscape. The combination of FES and network development policies within each network company form the starting point of transmission network planning and allow us to make strategic investments. SOF was developed in 2014 to identify the challenges and opportunities that exist in future years and to develop measures which ensure the operability of future networks. Last year we received very positive feedback from our stakeholders as well as suggestions for development and in SOF 2015 we have made a number of changes. We have provided more clarity on the relevance of the topics studied as part of this document, the whole-system impact of changes rather than focusing on transmission networks only and we have been clearer on our future operability strategy. As part of the SOF development process we held a series of webinars with a wide range of stakeholders including onshore and offshore transmission and distribution companies, manufacturers and technology providers, academics, generator companies and service providers. This was to challenge and review our analysis and reflect your views on both the system needs and delivery roadmap. The future operability strategy presented in SOF identifies activities such as development of new services, utilisation of existing and unused capability on the network and future research and development. Given the wide industry engagement feeding into this strategy, we have confidence that the right solutions and services will be developed which give the additional capability our power networks need to transition to a low carbon economy. We hope that this is a move that helps you, our customers and stakeholders, to realise new opportunities and ways of delivering them for the system.

I hope you find this a useful and interesting document. If you have supported our Future of Energy processes by participating in stakeholder engagement activities, I thank you. If you haven't, then I fully encourage you to get involved. We will continue to listen to your views and use them to help shape SOF 2016.

I also encourage you to provide your views by contacting us at **box.transmission.sof@nationalgrid.com**, completing the feedback form on our website, **http://www.nationalgrid.com/sof**, engaging us at future stakeholder events or coming to meet us at our offices.

Richard Smith,
Head of Network Capability
(Electricity)

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Chapter 1 Executive Summary

Executive Summary

Executive Summary

Changes in the generation mix and demand side combined with new technologies coming to the system bring a number of challenges and opportunities for operability of power networks. National Grid developed the System Operability Framework (SOF) in 2014 as an annual process in which we can study the Future Energy Scenarios (FES) in detail to assess the impact of changes in the energy landscape on system operability.

Following the first publication of SOF, we received an overwhelming response from our stakeholders and they encouraged us to further improve the SOF process and our capabilities to enhance the framework. This year we have made a number of improvements to SOF including a transparent and comprehensive stakeholder engagement programme from the beginning to the end of the process.

The selection of topics this year considered many factors including the analysis carried out last year, responses to the consultation in 2014, FES 2015 developments and stakeholder input from our pre-assessment workshop. There are number of new topics studied including an entirely new section on Embedded Generation which outlines opportunities to enhance the capability of the grid using embedded generation services either directly or under a Distribution System Operator (DSO) model. To give greater clarity to our stakeholders on "what" needs to be done and "when" we have also included a new section on Future Operability Strategy which was developed through extensive stakeholder engagement with the industry. In developing the 2015 SOF, **over 200** national and international organisations ranging from manufacturers, network companies, academia, generation and service providers, and DECC and Ofgem were approached, and consulted through a series of workshops and webinars.

We sincerely thank you for your support and valuable views that have been reflected in this document. This will continue in future engagements to ensure the tools and capabilities that our electricity networks require can be developed.

The SOF is based on in-depth technical assessments of the dynamics of power networks. Given the change in background against which these assessments are performed when FES is updated each year, we have performed the technical assessments using a combination of FES 2015 and our most recent operational experience. The technical topics studied this year have been grouped into a number of different categories resulting mainly from the change in generation mix and demand, and the new technologies on the system. A summary of the findings from each of the four topics is presented below.

System Inertia

System Inertia continues to decline under all our scenarios because of the lack of synchronous thermal power stations and high volume of converter connected generation technologies such as solar PV, wind and import across our High Voltage Direct Current (HVDC) interconnectors. This decline impacts RoCoF relays and in 2015 we see a greater need to expedite the relay setting update programme to avoid increasing operational costs in coming years.

The analysis shows a need for new services to help with managing the system frequency, as the **frequency response requirement will increase by 30-40% in the next five years.**

This trend continues and the response requirement in the period between 2025 and 2030 will be 3-4 times higher than the current level with limited access to currently available services. Our Enhanced Frequency Control Capability project (funded as part of the 2014 Network Innovation Competition), along with the Power Responsive campaign will facilitate both technical and commercial developments required to access new services.

System Strength and Resilience

In response to stakeholder feedback we have provided more detail on System Strength and System Resilience this year. The short circuit level decline is more pronounced and more extensive than in the 2014 assessment, developing in scale from 2019/2020 onwards across significant areas of the network. This decline shows that **natural support to the grid is reduced** and whilst converter connected technologies have some capabilities to provide the necessary support (such as dynamic voltage control) such capabilities must be further utilised. Amongst those, **greater access to the services from demand side is necessary** (energy storage, embedded generation, and load). This is particularly important in the context of voltage containment as it has been challenging for a number of years and the studies show a significant increase in need for additional reactive compensation over the next twenty years. In this section, the system restoration capability has also been reviewed in the context of unavailability of generation capable of black-starting the system and the behaviour of embedded generation during the black start. The assessments carried out in this section have shown **greater need to diversify the system services** (in addition to the services envisaged for inertia related topics) and the opportunities that exist to enhance the grid's strength and resilience. This includes utilisation of **flexibility services from windfarms, thermal generators, and interconnectors.**

Embedded Generation

This year, a new section on Embedded Generation aims to provide greater clarity on some of the direct impacts of an increase in embedded generation on system operability. Our analysis shows that to maintain the stability of the transmission system, new capabilities are required and both TSOs and DNOs must work more closely to address these issues given that a number of solutions require **coordination of services between transmission and distribution networks.** Another key highlight of this year's analysis is the need for review of Low Frequency Demand Disconnection (LFDD) relays which are affected by an increase in embedded generation. We are currently working closely with a wide range of stakeholders (DNOs, TOs, developers, Ofgem and DECC) to consider the whole-system impacts of embedded generation, and provide network solutions that facilitate economic and efficient design and operation of the whole-system.

New Technologies

The ability to accommodate New Technologies and their operational impacts is a major aspect of SOF. In addition to the topics presented last year which are reviewed again, we have highlighted the impact of new nuclear generation technologies on system operability including the need for flexibility in the future, and the impact of an increase in demand side technologies such as electric vehicles and energy storage. Different energy storage models are discussed, and the operability aspects of each option are assessed in order to form the basis for further work. It is recommended that **further network impact assessment is carried out ahead of the roll-out of new demand side technologies** to ensure that power networks are capable of operating without risk to the operability.

Executive Summary

Future Operability Strategy
Finally, the last section of this document sets out our **Future Operability Strategy**. In this section we have gathered the recommendations and potential solutions that were identified in individual topic assessments. Based on the timeline of operability challenges, **a pathway for the development of new services and capabilities is proposed.** In doing so, we have attempted to consider the technology readiness, the necessary coordination required and the potential capabilities which can be provided by a given technology or service.

We recognise, however, that further engagement and collaboration is required in the development and implementation of operability strategies. The short term and supplementary actions outlined in this document align with SOF 2015's top three strategy recommendations.

SOF 2015's Three Strategic Themes

- **Services and Capabilities**
  It is essential that new system services are developed to access existing enhanced capabilities from generation (particularly windfarm, solar and interconnector technologies) whilst facilitating the provision of new capabilities

- **Whole System Solutions**
  Transmission and distribution companies must continue to look at the whole-system impact of new technologies and greater access to services from demand side. In this context, the viability of accessing multiple services through different operator models across the whole system and layering of services should be considered from both technical and commercial perspectives

- **Increased Flexibility**
  The value of system services, in particular flexibility, should be considered by the manufacturers and developers of new plant, and form the basis of revenue streams which ensure new developments incorporate the system needs in their design. For example, the more flexible operation of new nuclear, gas and other synchronous plant is likely to be of much greater value going forwards.

Chapter 2
Introduction to SOF

System Operator Industry Interaction

SOF Development Process

System Operator Industry Interaction

2.1
System Operator Industry Interaction

The System Operability Framework (SOF) 2015 outlines how the future operability of the electricity transmission system is expected to change in response to the impact of developments outlined in the Future Energy Scenarios (FES) 2015. It also highlights new opportunities for developing innovative solutions and services to enhance the operability of the power networks in Great Britain.

The future operability of power networks requires long-term planning by both network companies and network users. Information required by different parties for planning and investment decisions is provided by National Grid as part of the suite of 'Future of Energy' documents:

- Future Energy Scenarios (FES) – provides transparent and holistic paths through uncertain energy landscapes to help government, customers and stakeholders make informed decisions. The FES presents possible energy futures in the form of scenarios based on addressing the energy trilemma of security of supply, affordability and sustainability
- Electricity Ten Year Statement (ETYS) – produced by National Grid with contribution from Scottish Power Transmission and Scottish Hydro Electric Transmission, the ETYS provides clarity and transparency on potential developments in the GB electricity transmission system. The ETYS is underpinned by the scenarios described in the FES, outlining potential development of network infrastructure through strategic modelling and design capability
- Gas Ten Year Statement (GTYS) – produced by National Grid in our role as gas transmission system owner and operator, the GTYS outlines potential future developments on the National Transmission System (NTS) using a scenario-based development process to help customers and stakeholders identify future connection opportunities
- Winter/Summer Outlook Reports – the outlook reports present a security of supply assessment for both gas and electricity on a biannual basis in the context of increasingly complex system operation at periods of low demand in summer as well as high demand in the winter. They also highlight the short-term need for ancillary services.

The long-term operability of the electricity transmission and distribution networks also requires in-depth assessment. Whilst this was historically covered to some extent as part of the ETYS, stakeholder feedback suggested a clear need to design a separate framework which interacted with existing development processes to highlight the challenges and opportunities of future networks. The System Operability Framework (SOF) was introduced in 2014 with an in-depth assessment of operability aspects of the electricity transmission system considering the changes in the energy landscape illustrated in the Future Energy Scenarios. The SOF has a number of distinct features:

- It identifies the key operability challenges facing the system operator and wider industry in the future through an established annual process involving technical assessments, review of operational experience and industry consultation

- It provides a holistic view of the growing technical challenges in system operability for GB electricity transmission stakeholders to raise awareness and seek innovative technology solutions for new and enhanced service opportunities
- It presents economic, commercial, and regulatory developments which may be needed alongside technical developments in order to achieve critical future services from stakeholders' feedback and impact assessment.

The SOF development process acts as a complementary risk management tool for the System Operator to continuously identify challenges which could arise as a result of the changing energy landscape. The SOF provides a platform for ongoing engagement with industry stakeholders to ensure that appropriate mitigating measures for operability issues are identified and discussed before decisions for implementation are made.
This ensures that a future operability strategy can be developed and enables appropriate economonic assessments to take place in line with the timescales identified for implementation of solutions.

SOF Development Process

2.2 SOF Development Process

Figure 1 shows the high level development phases of SOF. Through technical assessments, each of the Future Energy Scenarios is studied in detail across a breadth of operability topics. Future operability studies and dynamic performance assessments are applied to the generation and demand backgrounds to highlight key variances between scenarios. Results are assessed against the future performance requirements of the system in order to determine the severity and timescale of operability challenges which lie ahead. The process provides assurance that potential risks to system operability are recognised and suitable mitigating options are identified before they are required.

Figure 1
SOF Development Process

Future Energy Scenarios

Changes in the Energy Landscape

- Changes in the generation mix
- Embedded generation growth
- Demand side developments
- Increased interconnection.

Performance Requirments

A Secure and Operable System

- Maintain an operable system within frequency and voltage limits
- Minimise system constraints
- Facilitate the energy market.

Operational Challenges

System Inertia and Strength

- Significant inertia and strength reductions
- Requirements for primary response
- Managing RoCoF
- Protection
- Power quality.

Solutions and Opportunities

Development of a Smarter Grid

- Operation of plant and network under low load condition
- Rapid response
- Demand side management
- System wide control capability.

2.2.1
Future Energy Scenarios (FES)

The FES informs the background against which SOF assessments are carried out by providing an envelope of possible energy futures to explore. Each of the scenarios makes different assumptions about future prosperity and green ambition, underpinned by a need to tackle the energy trilemma.

Designed to provide a framework to study possible energy futures, the scenarios are reflective of uncertainty in policy, economy and technology environments. The FES does not provide a forecast or probabilistic analysis of scenarios, but rather a scope of potential drivers and impacts for consideration. The four scenarios presented in the FES 2015 are outlined in Figure 2: Consumer Power, Gone Green, Slow Progression and No Progression.

Figure 2
The Future Energy Scenarios

SOF Development Process

- **Consumer Power (CP)** is a world of relative wealth, fast paced research and development and spending. Innovation is focused on meeting the needs of consumers who focus on improving their quality of life
- **Gone Green (GG)** is a world where green ambition is not restrained by financial limitations. New technologies are introduced and embraced by society enabling all carbon and renewable targets to be met on time
- **Slow Progression (SP)** is a world where slower economic growth restricts market conditions. Money that is available is spent focusing on low cost long-term solutions to achieve decarbonisation, albeit later than target dates
- **No Progression (NP)** is a world focussed on achieving security of supply at the lowest possible cost. With low economic growth, traditional sources of electricity and gas dominate with little innovation affecting how we use energy.

The FES 2015 presents a future where the installed capacity of non-synchronous generation (such as solar PV, wind and interconnectors) continues to increase under all four future scenarios. From an operability perspective, non-synchronous generators have very different characteristics compared to synchronous generators (e.g. conventional thermal power plants) which will change the overall performance of the system. The amount of non-synchronous generation as a proportion of total generation at any given time therefore has a significant impact on the dynamic response and inherent strength of the AC system in steady-state. Demand side changes illustrated in the FES, such as the uptake of electric vehicles and storage, present additional challenges for the balancing and operation of the grid.

2.2.2 Performance Requirements

The performance requirements of a large AC power system are underpinned by the properties of the network and characteristics of generation and demand. The diversity and location of generation technologies and their ability to provide support to the grid is critical to the performance of the system as a whole. Understanding the operability impact of changing system dynamics is critical to the development of future networks.

The islanded AC nature of the GB power system necessitates specific performance requirements to ensure that electricity networks are operated in a safe, secure, economic and efficient way. The continuity of energy supply is fundamentally dependent on the reliability of the power system's components. Reliability is a key indicator of how well the system has performed over a given time period and there are different ways of expressing this. One way of measuring overall power system reliability is to measure the number of hours that supply continuity has been interrupted as a result of the failure of network components. The level of reliability of the GB electricity transmission network is shown in Table 1. The reliability figures indicate the percentage of time that the transmission network was able to supply energy demand.

Table 1
NETS Historical Reliability of Supply

2014/15	2013/14	2012/13	2011/12	2010/11
99.99987%	99.99991%	99.99975%	99.99954%	99.99969%

It is important to note that whilst the availability of the transmission network has a major impact on the ability to achieve such a high reliability, it is insufficient to ensure continuity of future power supply. This is determined to a greater degree by the system performance characteristics which impact overall reliability levels. These characteristics change significantly across a given time period due to variation in demand on the network and changing sources of electricity generation. Both peak and off peak periods present a differing range of challenges for the system operator:

- At high demand (peak) periods the key focus of the system operator is to ensure that there is sufficient generation margin to meet demand, adequate frequency response, enough reactive power support to avoid voltage collapse and the required transmission capability to meet regional demands
- At low demand (off peak) periods, there are fundamental differences in system characteristics which arise from the reduced number of generators which are running and the lightly loaded transmission and distribution networks.

Throughout the topics considered, the SOF assesses both high and low demand performance, identifying system tipping points based on key performance parameters (i.e. when the minimum performance requirement cannot be achieved with the means currently available to the system operator). This method allows the degree of divergence from performance benchmarks to be assessed and enables causes to be accurately studied along with system effects so that mitigating options can be developed.

2.2.3 Operational Challenges

Operating a power system island with a significant volume of non-synchronous generation connected to both transmission and distribution networks presents many unique challenges which need to be managed. Changes such as reduction in system inertia, falling system strength, increases in embedded generation and the prospect of new technologies interfacing with the network create a range of operational challenges which are studied as part of SOF.

SOF Development Process

Based on stakeholder feedback throughout the development of SOF 2015, the technical assessments presented in this document are grouped into the four primary topic areas. Whilst there is naturally significant interaction between these topics due to the complex nature of operational challenges, stakeholder feedback was that this provided a clear framework for the presentation of findings. The SOF 2015 programme of stakeholder engagement and topic development is outlined further in Chapter 3, with the assessments and findings detailed in Chapters 4, 5, 6 and 7. The four topics presented are as follows:

System Inertia is a measure of the system's inherent resistance to change which arises due to the energy stored in rotating machinery connected to the grid. The proportion of directly coupled synchronous generation relative to non-synchronous generation is decreasing and an important impact of this transition is the reduction in system inertia. System inertia is a key metric which concerns the transmission system's ability to respond to real-time events on the system and is a core topic of study.

System Strength and Resilience is another critical area impacted by the changing nature and location of electricity generation. As the synchronous plant in operation at low demand periods reduces, a number of challenges arise relating to the inherent strength of the network, suitability of protection devices and emergency restoration strategy with a low volume of thermal generation. Existing and future HVDC interconnectors provide a valuable resource for improved security of supply through the ability to exchange power with continental Europe however may also present a number of operational challenges as the dynamics of the system change.

Embedded Generation is an area of significant recent development. As reflected in FES 2015, the volume of embedded generation, particularly under Consumer Power and Gone Green scenarios, grows significantly in the future. This is reflective of a recent growth in Embedded Generation (EG) in the form of both Distributed Generation connecting to distribution networks and Micro Generation which is less than 1MW in size. In particular, an increasing quantity of solar PV and wind generation causes challenges in operating a low demand transmission network during sunny and windy periods. There is also an associated challenge in accurately forecasting output from intermittent generation technologies and the associated impact on transmission system demand. Consequentially, there is a greater collaborative role for both transmission and distribution networks in managing embedded resources to facilitate stable operation system through a whole system approach.

New Technologies have a significant role to play in addressing the challenges of future power systems. As an islanded network, the future performance of the GB system will be influenced by the interactions between these technologies. New nuclear generators are expected to connect to the GB transmission system in the future and require careful consideration from a Grid Code compliance perspective, particularly with regards to frequency response, voltage control, system stability and emergency system restoration. The impact of technology changes such as the transition to electric vehicles and the potential impact on the demand curve must also be considered.

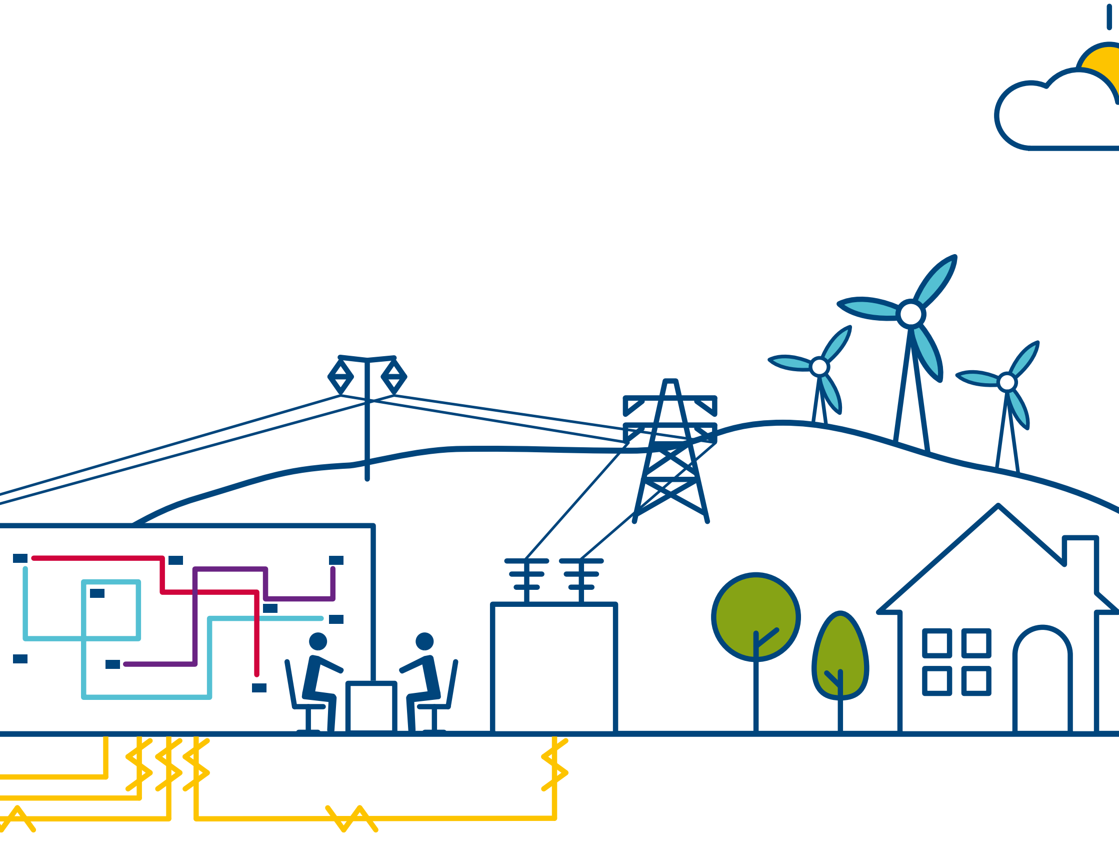
2.2.4
Solutions and Opportunities

The measures and tools available to the System Operator (SO), Transmission and Distribution Network Owners (TOs and DNOs) and network users need to evolve to ensure they are fit for purpose and safeguard the operability of future networks. New capabilities must be developed in suitable timescales to mitigate the challenges arising from changes in the energy landscape.

The capabilities of existing technologies to deal with the range of operability challenges presented are assessed, including capabilities which are:

- Inherent to the nature of the network components, for example the support provided to the grid by synchronous generators when they are running
- Provided to the system as part of the obligation of industry parties which are codified in industry documents such as the Grid Code or the Distribution Code such as the minimum performance requirement of generators
- Procured through contracts or bilateral agreements such as the provision of ancillary services
- Used in transmission and distribution networks such as the ability to control the voltage within limits
- Require adjustments to the control systems, hardware or existing plants and network components
- New technologies or assets which do not exist currently inevitably have longer lead time to be developed.

SOF 2015 identifies appropriate technical solutions based on the assessments and the necessary timescales for implementation. A holistic view of Future Operability Strategy is presented in Chapter 8 to provide better clarity of system needs and priorities for development of new capabilities.



Chapter 3 Development of SOF 2015

Stakeholder Engagement

Chapter three

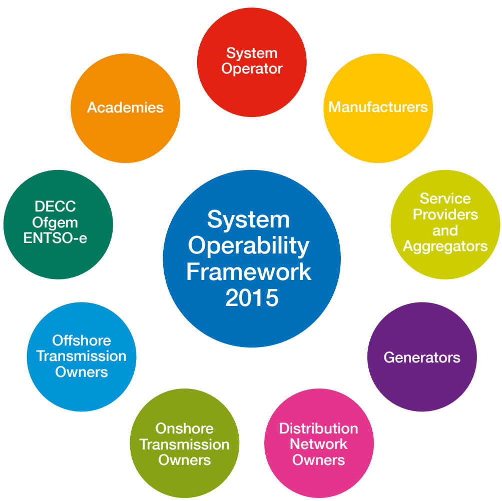
3.1 Stakeholder Engagement

A key aspect of the SOF 2015 development process has been an enhanced programme of stakeholder engagement throughout the year. National Grid recognises that many future transmission operability issues relate to whole-system challenges and are new to the power networks in GB and across the world. Wider industry consulatation and cross party solutions are critical in the identification and implementation of mitigations.

As part of the development for SOF 2015 we reflected on the feedback we received through last year's industry consultation. Throughout this document we have noted where we have acted on feedback and how, with ongoing industry engagement, we plan to further improve SOF to make it a more useful document for our stakeholders. There are a number of important areas in particular which we have acted on:

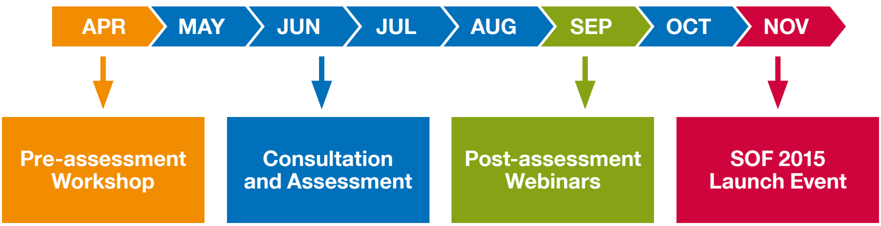
- Early engagement in the process
- External challenge and review of the analysis
- Additional focus on operability challenges resulting from changes in distribution networks and the whole system impact
- Indication of potential future solutions and timelines
- Highlight non-technical barriers in achieving solutions such as commercial and regulatory.

Figure 3
SOF Industry Stakeholders



In April 2015, we hosted a pre-assessment workshop with representation from a cross section of the industry. The workshop provided an opportunity for over 70 stakeholders to inform the SOF 2015 development process and the topics to be studied. As part of the event a number of attendees were invited to present on their perspective of current and future operability issues which impact the wider GB network. The proposed topics of study for SOF 2015 were presented and tested with the audience for feedback and review to inform the assessments for this year. Based on the information collected, we commenced study work in March which ran through to August during a prolonged period of assessment and consultation.

Figure 4
SOF 2015 Stakeholder Engagement Timeline



In the development of SOF 2015, we also reached out to a number of different stakeholder groups prior to publication through a series of post-assessment webinars presented in September. The purpose of the webinars was to present key findings and seek the latest information from industry colleagues on innovations, products and services which could be developed to faciliate solutions. In particular, the timing of the webinars provided a final opportunity to develop and enhance assessments prior to SOF publication based on feedback. The webinars were open for all to attend and encouraged focussed discussion with over 120 stakeholders across three sessions targetted for different industry groups:

- TOs, DNOs and OFTOs
- Researchers and Manufacturers
- Generators and Service Providers.

SOF 2015 was released at a launch event in November where the industry was invited to view findings in full and engage in discussion on future GB system operability and service provision. Following the publication of SOF 2015 National Grid remains committed to stakeholder engagement and acting on feedback to enhance assessments and improve SOF year on year.

Assessment Methodology

3.2 Assessment Methodology

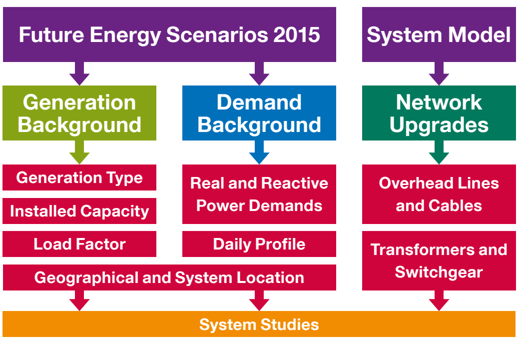
The SOF assessment methodology is designed to provide a systematic and robust structure for system operability studies. The first stage in this process is to re-dispatch the current system to match the generation and demand datasets provided by the Future Energy Scenarios against which future operability assessments take place.

The FES datasets provide a year-on-year breakdown of the Balancing Mechanism Units (BMUs) which are anticipated to be connected to the transmission system in the future based on pending connections and industry intelligence. This includes data on installed capacity, location and typical load factor for new units dependent on technology-type. The data sets also reflect old generating units which will reach the end of their life within the timescales of the SOF studies.

Datasets have been developed through the FES process which reflect year-round demands including winter peak and summer minimum conditions. Historically, national demand minimum on the National Electricity Transmission System (NETS) has occurred in the early hours of the morning. One of the significant challenges posed by the increased levels of embedded solar PV in the 2015 scenarios is a shift to early afternoon NETS demand minimum under all scenarios except No Progression within the next 10 years. This is due to the offset effect which embedded solar generation has on transmission system demand when at maximum output during the sunniest period in the middle of the day. The operational implications are considered in greater detail across the assessment sections in Chapters 4, 5, 6 and 7.

In terms of assessment methodology, there was a clear driver to assess both AM and PM demand minimum datasets to better understand net demand levels and generation mix on the NETS. FES 2015 provided intelligence on embedded generation technologies, installed capacities and locations in order to dispatch transmission connected generation and demand appropriately.

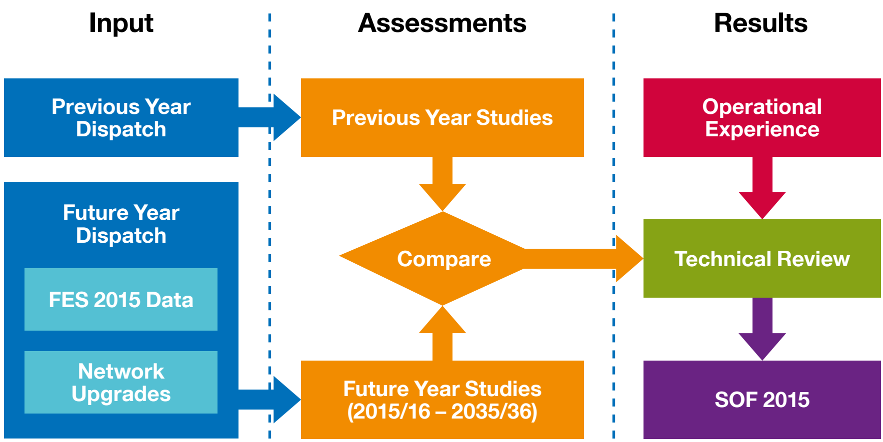
Figure 5
System Studies Data Input



The future generation and demand backgrounds were applied to network models which account for planned future network upgrades. Operationally, planned system maintenance outages typically occur between clock changes in the March – October period. It was therefore important that summer minimum studies accounted for a typical system running arrangement during this period. Dependent on the requirements of the study, a range of network outages or depleted network conditions were applied to create a system more reflective of reality.

The SOF technical assessment methodology was designed to study the future NETS in a detailed and systematic way versus current system performance. In order to provide a comparison baseline for future year studies, the FES provided a view of the current year generation and demand data. For more detailed studies of specific system conditions and events, real historical dispatch data was used as captured by metering devices feeding through the energy management system of the control room. Unless otherwise stated, all assessments assumed that future generation units comply with Grid Code mandatory requirements and the Security and Quality of Supply Standard (SQSS) in current form.

Figure 6
SOF Assessment Methodology



SOF 2015 Topics

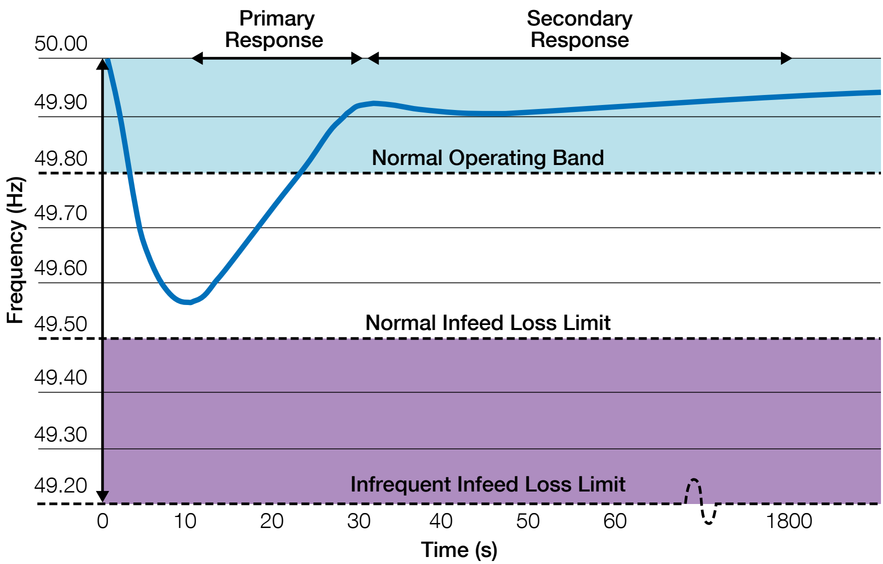
Chapter three

3.3
System Inertia

System inertia is the primary source of electricity system robustness to frequency disturbances which arise due to an imbalance of generation and demand. National Grid has a licence obligation to control frequency within ±1% of nominal system frequency (50±0.5Hz) except under abnormal conditions and must therefore ensure that sufficient generation and/or demand is held in automatic readiness to manage all credible frequency events.

Dynamic response is a continuously provided service which is used to manage normal second by second changes on the system and can be considered in terms of Primary Response (10s – 30s) and Secondary Response (30s – 30mins) to an event. Static Response is typically a discrete service triggered at a defined frequency level. Figure 7 depicts the timescales relevant to the different forms of response available.

Figure 7
Illustrative Frequency Response Timescales



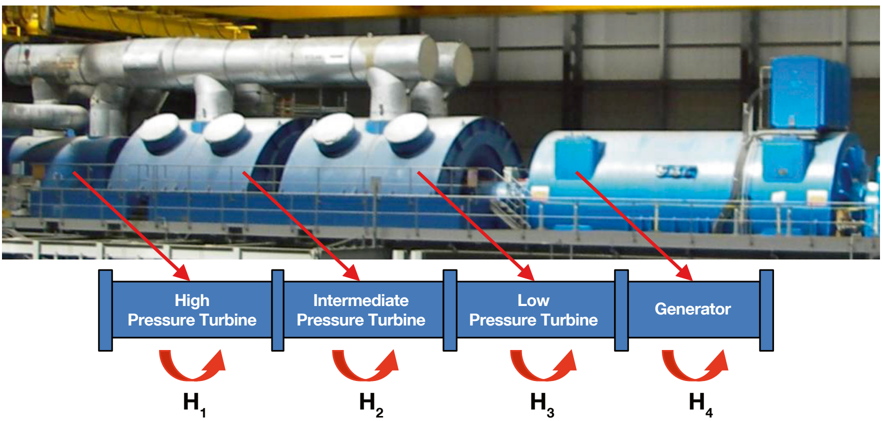
National Grid also uses reserve to balance the system and deal with unforeseen demand increases and/or generation unavailability. Reserve requires access to sources of power variation in the form of either generation or demand comprised of both synchronous and non-synchronous sources.

Sudden frequency disturbances can occur due to loss of load or generation. The higher the inertia on the system, the slower the Rate of Change of Frequency (RoCoF) to any sudden disturbance and the greater the damping effect. Inertia on the system is provided naturally by the energy stored in the rotating mass of the shaft of the electrical machines, including both directly connected generators and motors. It is critical to ensure that there is sufficient inertia to secure the system in the event of an instantaneous change in generation or demand in line with the levels defined in the Security and Quality of Supply Standard (SQSS).

Inertial Contribution from Synchronous Generators

Large synchronous generators are the main sources of inertia for the transmission system and play a major role in limiting RoCoF and in the containment of system frequency changes following an unscheduled loss of generation or demand from the system. The inertial requirements for transient (rotor angle) stability are also mainly provided by synchronous plant. In a large synchronous generator, inertia is provided by the turbine shaft and its associated attachments (such as the alternator and high, intermediate and low pressure turbines).

Figure 8
Inertial Contributions from a Synchronous Power Plant's Rotating Masses



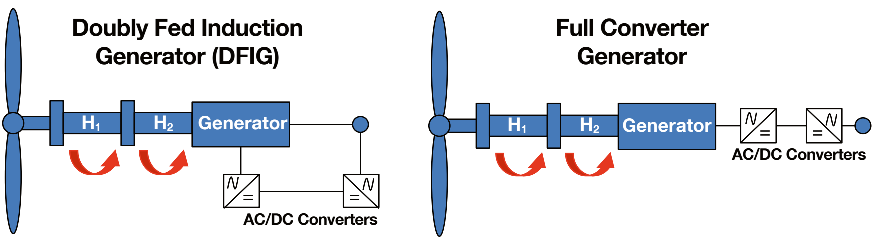
SOF 2015 Topics

The inertia constant "H" for a rotating machine can be calculated from the sum of contributions provided by each element of the directly connected rotating mass. "H" is defined as the ratio of physical rotational kinetic energy to the MVA rating of the machine. Its units are MW.s per MVA or equivalently, seconds. The inertia of the total system can be expressed in MVA.s (or GVA.s) by totalling contributions from each machine, calculated by multiplying the MVA rating of the machine by its inertia constant "H".

Inertial Contribution from Wind Farms, Solar PV and HVDC Links

Except in the case of simpler induction generator designs, wind turbines provide little or no inertia to the system. This is because in both doubly-fed induction generator and full converter designs, the wind turbine's rotating mass is de-coupled from the transmission system by either AC/DC converters or controller actions which offset the inertia effect (see Figure 9).

Figure 9
Wind Generation Technologies



These two newer wind technologies therefore cannot be used in the conventional sense as sources of natural inertia for the purpose of frequency response. They can however vary their MW output to provide so-called "synthetic" inertia. The provision of fast response from wind farms has advantages which are further discussed in Chapter 4.

Unlike wind turbines, solar PV installations do not contain any rotating parts and therefore have no natural inertia, however, it is similarly possible to vary MW output for frequency response purposes. It may therefore be possible for solar PV farms to provide some degree of synthetic inertia or alternatively, be combined with energy storage technologies to enhance their capabilities. Storage also has a potential secondary benefit of better distributing the typical solar PV bell curve output more evenly throughout the day.

HVDC links similarly have no natural inertia and when they are operating in import mode to GB could displace synchronous generation which does provide inertia. Some HVDC links are however already being used as static response. When the system frequency falls below a pre-defined level, a change in MW output is triggered which contributes to frequency response requirements. The provision of synthetic inertia from HVDC links requires coordination between the system operators at both ends of the links as well as the interconnector operator. The capability of a particular HVDC link to provide synthetic inertia depends on both technology type and system conditions at both the sending and receiving ends.

As part of the System Inertia topic three assessment areas were investigated:

Whole System Minimum Inertia – system inertia at future minimum demand periods where the proportion of Non-Synchronous Generation (NSG) is high and system inertia is lowest.

Rate of Change of Frequency (RoCoF) – low system inertia impact on the ROCOF in future years.

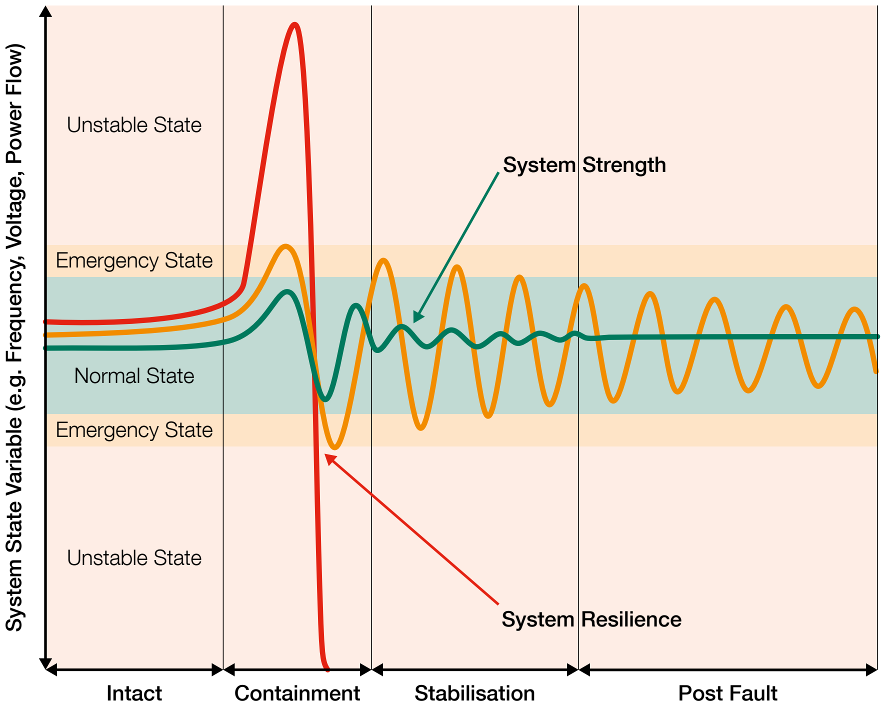
Frequency Containment – increased response holding requirements associated with decreasing system inertia.

SOF 2015 Topics

3.3.1
System Strength and Resilience

System strength represents an indicator of inherent system robustness relating to properties other than inertia. System resilience represents the margins of operability and response options when the system is in a stressed state. This is illustrated in Figure 10.

Figure 10
System Strength and Resilience Relating to a Disturbance



At any given time the network can be considered as occupying one of three possible system states:

- Normal State – where the system is operating between acceptable limits to satisfactory levels of quality and availability of supply. This is the default planned state of the system
- Emergency State – where the system is subject to a disturbance, temporarily behaving beyond the bounds of normal regulation but in a region of performance for which equipment is designed to respond to complement recovery. An example of this would be the response of the system during a fault that protection would rapidly clear. These scenarios are not frequent however do occur and the system should be robust against them. The scope of potential conditions and required behaviour of the system are defined in both Grid Code and the Security and Quality of Supply Standard (SQSS)
- Unstable State – where the system is subject to a disturbance beyond designed operation and the bounds of emergency conditions. Plans are in place to recover the system which involves further action to mitigate the consequences of the disturbance. Recovery or re-establishment will occur following the effect of such a disturbance which occurs beyond the horizon of normal and containment states of operation. Given the presence of codes, standards and industry processes, events which could instigate an emergency state are expected to be of exceptionally low probability and frequency.

For a disturbance, the network can be considered to undergo 4 phases of behaviour:

- Intact – the initial timeframe ahead of a disturbance
- Containment – where the system has undergone a disturbance and responds ahead of any instructed action relative to its natural behaviour and the natural behaviour of automated control systems to mitigate
- Stabilisation – where the prolonged duration of any residual consequences of the disturbance are mitigated based on a combination of automatic control responses and instructed or supplementary designed responses to the event
- Post-fault – where the disturbance has been removed or mitigated or its consequences have run full course such that the end state following the disturbance can be clearly defined.

System Strength is a measure of how well the various inherent behaviours of control systems and dynamics of network behaviour combine to ensure that the system can remain within a normal state of operation or return from an emergency state to normal state under the majority of situations.

System Resilience acts to mitigate the impact of the system being in an unstable state, either by changing the network problem (for example shedding demand or disconnecting of network elements) or by implementing an effective mechanism of restoration following an incident.

Unlike the system inertia, which can be defined on a national scale, the factors contributing to system strength tend to be much more regionally specific, for example:

- The proximity of synchronising torque, voltage control and reactive injection during a fault
- The extent of network interconnection and its balance against network loss and gain
- The function and duration of operation of protection systems and other automation
- The function, speed and capability of control systems proximate to the area considered.

One of the conventional metrics of power system strength at a given point is Short Circuit Level (SCL), often also referred to as fault level or fault infeed. An important characteristic of conventional synchronous plant is the fault infeed it provides. One of the challenges identified in the System Strength and Resilience topic is that many new generation technologies (particularly non-synchronous generation) provide significantly lower levels of fault infeed and/or fault infeeds which rapidly decline within protection operation timescales.

SOF 2015 Topics

It is anticipated that as the generation mix shifts to accommodate more renewable generation and some conventional thermal power stations close, short circuit levels across the system will reduce. In addition to system inertia, short circuit level is an important factor in maintaining the stability of the grid and the behaviour of the system is heavily dependent on it.

System resilience cannot be measured in terms of technical factors such as short circuit level, but rather can be judged on the comprehensiveness and effectiveness of responses available across a range of conditions which may occur beyond codes and standards. Each is unique in nature however the range of resilience actions that the operator currently employs can be summarised as:

- Demand control actions (Grid Code OC6) to DNOs or large directly connected demand customers to reduce demand at times of system margin stress, the first step normally being to affect a voltage reduction expected to correspond to a proportionate active power change
- Balancing control of demand group actions (Grid Code BC2.6) under emergency conditions to DNOs to request reductions in demand or distributed generation to enable the operator to support balancing actions
- Request of maximum generation operation (limited Mvar range) or minimum generation operation (without high frequency sensitive mode) operation to support margin
- System islanding and black start (Grid Code CC.6.3.5, OC5.7, OC9) to restore the system from a de-energised or selectively de-energised state.

System strength and resilience with regard to both energy balance and dynamic behaviour can also be either positively or negatively influenced by external networks connected via HVDC links and the services they provide. Where appropriately specified, designed and operated, these services represent a powerful tool to extend the range of system operability.

Those areas which are most subject to change in the FES are considered in the assessments outlined below, noting that some related subjects such as minimum transmission generation levels with respect to new nuclear projects and Low Frequency Demand Disconnection (LFDD) are considered separately elsewhere in this document:

- Declining Short Circuit Levels and Protection – investigation of national and regional variations in declining short circuit levels and the ability to detect faults on the system
- Voltage Dips – the effect of reduction of system SCL, and the impact on voltage recovery following a fault, as well as the wider effect of voltage dips and potential impact on disconnection of embedded generation without low voltage ride through capability
- Voltage Regulation and Containment – the effect of reduction of system SCL, and impact on the ability to control the voltage
- Power Quality – the effect on changing SCL on various power quality related issues such as resonance and harmonics, and negative phase sequence (NPS)
- LCC HVDC Commutation Failure – the performance of LCC based HVDC links when the fault level at the connection points (in GB) drops and it may affect the link to operate in import mode
- Demand Control by Voltage Reduction – effectiveness of demand control by voltage reduction when system SCL is low
- System Emergency Restoration – ability to black start the system in the future and discussion around the system behaviour under emergency restoration.

3.3.2
Embedded Generation

Within this document, embedded generation refers to generation which does not have a contractual agreement with the National Electricity Transmission System Operator (NETSO) and reduces the overall demand on the National Electricity Transmission System (NETS) when generating. It is considered as generation connected below transmission voltage levels of 275kV in England and Wales and 132kV in Scotland. Embedded generation can be broadly split into two categories:

- Distributed Generation (DG) is generation connected to a distribution network and equal to or greater than 1MW in size up to the transmission network mandatory connection thresholds of 100MW for the National Grid Electricity Transmission (NGET) area, 30MW for the Scottish Power (SP) area and 10MW for the Scottish Hydro electric Transmission (SHET) area
- Micro Generation (MG) is generation which is below 1MW installed capacity.

In 2014/15 the GB power system has seen a significant increase in the volume of embedded generation connecting to distribution networks, with growth in solar PV generation being of particular note. Whilst there will always remain a degree of uncertainty in future trends, the significant increases outlined in FES 2015 will have an impact not just on distribution networks, but on a number of aspects of whole-system operability. In SOF 2015 we have therefore studied some of the whole-system effects of an increase in embedded generation:

- Regional System Stability – the effect of increasing embedded generation (non-synchronous) in combination with transmission system generation mix changes on system stability in four regions: the South West, the South East, Scotland and North Wales
- Low Frequency Demand Disconnection (LFDD) – the effectiveness of LFDD schemes (used as an emergency frequency control measure) at different times of the year
- Active Network Management (ANM) – the effect of various ANM schemes in managing local constraints and consequences of uncoordinated transmission/distribution actions
- Demand Forecasting with High Levels of Embedded Generation – the challenges arising from rapid growth in solar PV on accurate demand forecasting.

SOF 2015 Topics

Chapter three

3.3.3
New Technology

New technologies deployed on the transmission and distribution systems, particularly in instances of limited operational experience, may pose new challenges to the industry. The satisfactory operation of the network in the presence of these technologies therefore has to be assured through study, testing and monitoring. To ensure operability is maintained, the obligation of parties to each other in terms of design and performance criteria is codified in number of industry documents such as the Grid Code, the Distribution Code and the Security and Quality of Supply Standard (SQSS). In this section an overview of new technologies which will require technical consideration in the future is presented:

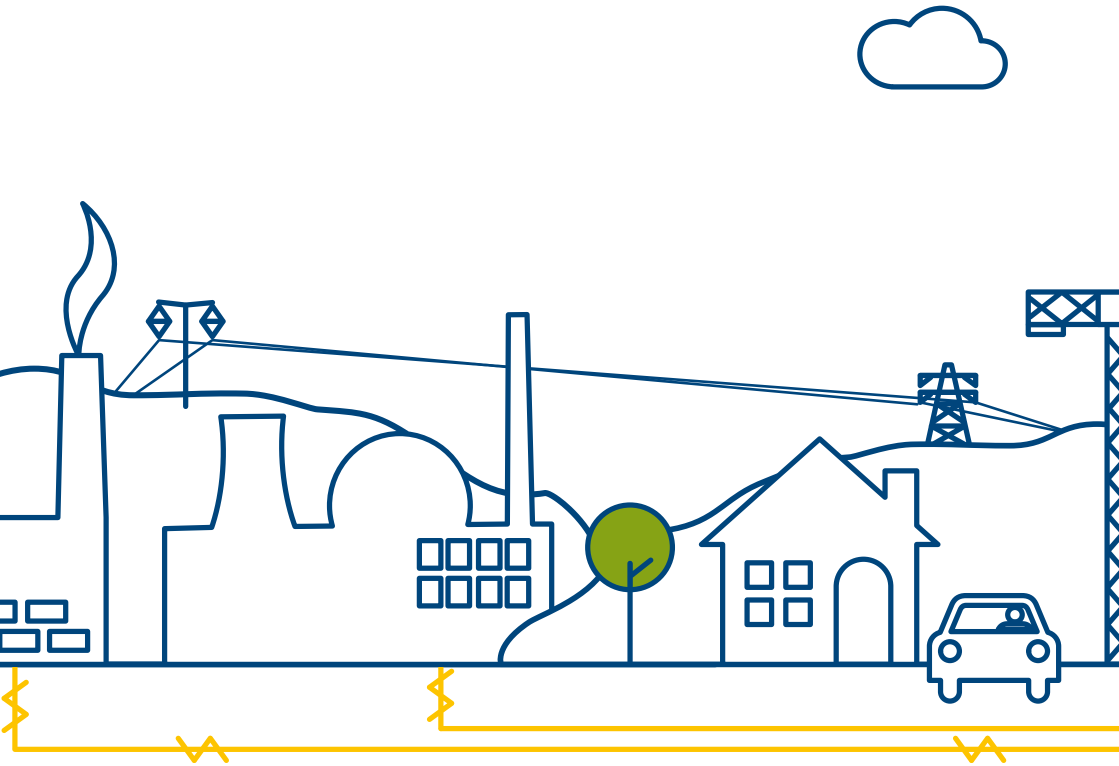
- Sub-Synchronous Resonance – the interaction of generator shafts with series capacitors, HVDC converters and an assessment of the potential for sub-synchronous resonance
- Control Interaction – the potential undesirable interaction between network components
- New Nuclear Capability – the characteristics and capabilities of new nuclear reactor technologies and potential impacts on the grid
- Demand Side Technologies – the impact of increase in new demand technologies such as energy storage, heat pumps and electric vehicles.

SOF 2015 Topic Map

3.4
SOF 2015 Topic Map

Figure 11
SOF 2015 Topic Map

Topic	Assessment	Impact
System Inertia	Whole System Minimum Inertia	Decreasing whole system minimum inertia in future years
	Rate of Change of Frequency (RoCoF)	Trip of embedded generation protected by RoCoF relays
	Frequency Containment	Increase in volume of response required
System Strength and Resilience	Declining Short Circuit Levels and Protection	Difficulty detecting and clearing faults on weaker networks
	Voltage Dips	Widespread voltage dips and disconnection of embedded generation
	Voltage Management	Voltage containment and need for additional reactive compensation
	Power Quality	Power quality issues and need for additional filtering
	LCC HVDC Commutation Failure	Inability to operate LCC HVDC links in weak network conditions
	Demand Control by Voltage Reduction	Reduction in effectiveness of demand reduction by voltage control
	System Emergency Restoration	Reduction in black start plant and system restoration challenges
Embedded Generation	Regional System Stability	Stability issues associated with increase in embedded generation
	Low Frequency Demand Disconnection	Risk of cascade loss of generation should LFDD relays operate
	Active Network Management (ANM)	Uncoordinated TSO/DSO actions in constraint management
	Demand Forecasting	Increased demand forecasting error and increase in balancing actions
New Technology	Sub-Synchronous Resonance	Resonance issues and torsional shaft interaction
	Control System Interaction	Oscillations arising from uncoordinated control systems
	New Nuclear Capability	System flexibility and the impact of frequency response
	Demand Side Technologies	Changes in demand profile and impact of demand side technologies



Chapter 4
System Inertia

Key Messages

4.1
Key Messages

- System inertia is expected to reduce between now and 2035 during periods of low demand and/or high renewable generation. In future years, the partial recovery of declining inertia is heavily dependent on new nuclear connections
- New analysis reveals that frequency containment requirements are expected to increase significantly over the next 15 years during summer minimum periods. Over the next five years this amounts to an increase of 30-40% in primary response requirements. Gone Green presents challenges due to an increase in the largest generator before 2025. For the remaining scenarios an increase in response requirements occurs by 2030 at which time the need for primary response holding during summer periods across all scenarios has increased by a factor of 3-4 across all scenarios
- New frequency response providers must be sought to meet the frequency response requirements projected for the future
- The development of new services to offer both faster response and increase the system inertia, as proposed by the Enhanced Frequency Control Capability (EFCC) project, are necessary to access greater frequency control capability in the future.

Whole System Minimum Inertia

4.2 Background

System inertia is proportional to the sum of stored energy in the rotating masses of machines (generators and motors) which are directly connected to the electricity grid. High system inertia makes for a strong system that can handle transient changes in system frequency and helps in stabilising the system. Lower system inertia increases the likelihood of rapid system changes and instability arising from progressively small disturbances that could lead to severe faults or loss of generation or demand.

Traditionally the bulk of electrical energy has come from transmission-connected thermal power plants with large rotating masses which contribute to high system inertia. As the volume of asynchronous technologies such as solar PV, wind and importing HVDC interconnectors increases, the total system inertia reduces. It is therefore important to study the impact of such changes on system inertia and system operability and to seek ways to respond to new challenges.

In practical terms, total system inertia is made up of contributions from transmission-connected generators, distribution-connected generators and the demand side (e.g. synchronous motor loads):

Total System Inertia =
Inertia from Transmission Generation +
Inertia from Embedded Generation +
Inertia from Demand

The amount of inertia a generator contributes to the system depends on the size and type of the generator when it is running and is not directly coupled to how much power it is producing. Even if a generator is part-loaded, as often is the case during the low demand periods, its MVA rating has to be taken into account when calculating its contribution to the total system inertia.

Similarly, the inertia contribution from smaller embedded generators can be estimated if the following factors are known:

- Generator fuel type/inertia constant
- MVA rating
- Generation pattern/load factor
- Connection method (direct/uses a converter).

During low demand periods, a higher proportion of the demand is met by non-synchronous sources such as wind generators, solar PV and interconnectors (which displace the synchronous generators when importing to GB). These technologies do not provide natural inertia in the same way as conventional generators. Low demand periods therefore present the most onerous case for issues associated with the reduction of system inertia as renewable technologies typically have higher merit order priority. In addition, as is discussed later in this section, the range of “traditional” operability tools available to the System Operator is often most limited at those periods which highlights the need for new and more innovative solutions in coming years.

Whole System Minimum Inertia

4.2.1
Impact on Operability

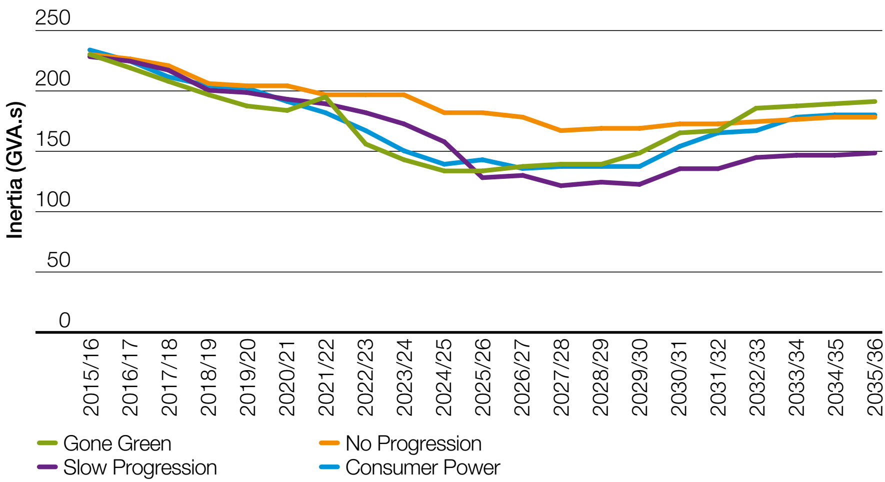
Since system inertia describes the system's opposition to change, significant reductions in system inertia can have an effect on:

- Rate of Change of Frequency (RoCoF): A number of embedded generators on the system are protected against the loss of mains (the condition where the local network loses the connectivity to the rest of the system) using relays which detect the rate of change of frequency (RoCoF). If the RoCoF following an unexpected significant loss of generation or demand is greater than the RoCoF relay setting of an embedded generator, then that generator will be tripped off the system. This condition will arise not as a result of loss of mains, but due to widespread high RoCoF across the system following a power imbalance. This could potentially occur for a large number of generators at once, with the result being a change of frequency on the system that is too large to contain as the loss of generation increases. The reduction of system inertia in the future will give rise to changing RoCoF levels on the system and it is therefore studied in detail in this section
- Frequency Containment: The first challenge which could potentially be encountered following a loss of generation/demand is that of RoCoF relay tripping, however, the next is that of Frequency Containment, i.e. stopping the frequency from falling too low or rising too high. To prevent this from happening, an amount of plant is held on the system at all times to provide frequency response. The precise amount of response held is dependent on the system demand (inertia) and the largest loss risk in force at a particular time. Since the inertia on the system is decreasing, and projected to continue to decrease for the foreseeable future, frequency containment is an increasing area of challenge. Based on stakeholder feedback, for the first time SOF now includes the results of studies which assess the frequency response requirements of the system over the next 20 years.
- System Stability: The level of inertia in a region is an important factor for the operation of the system during the initial period of disturbance or fault. It is crucial to have sufficient inertia on the system such that it remains stable after, for example, a short circuit event. In such a scenario, a system with an insufficient level of inertia would experience a large frequency disturbance resulting from an instantaneous local voltage depression in the region of the fault followed by slow voltage recovery. Stability is achieved by both the rapid provision of power and other frequency dependent behaviour discussed, however, it is also critical to ensure that sufficiently dynamic reactive power reserves are dispatched from available providers to stabilise and recover the voltage in the affected area. This prevents the disturbance from giving rise to large power angle swings which could complicate the return to normal operation of both synchronous and non-synchronous generation following a fault.

4.2.2
Assessments and Key Findings

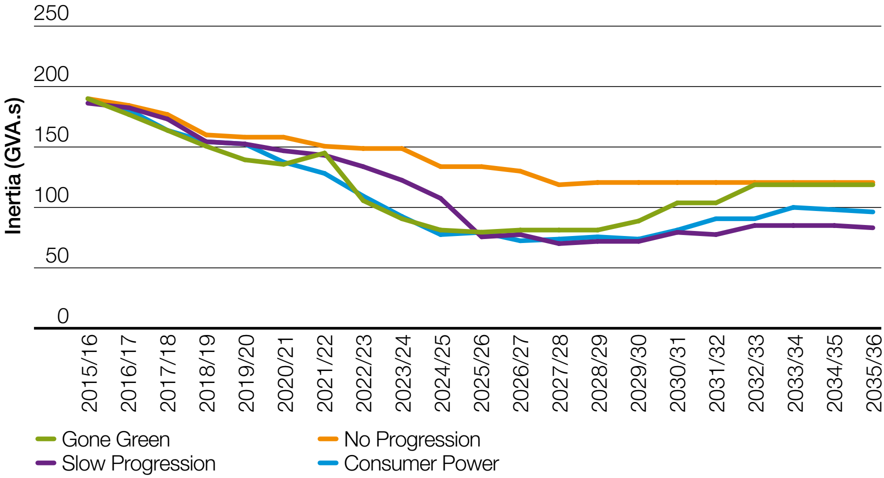
The minimum system inertia for future years was estimated based on FES data using the methodology described in Chapter 3. The results in Figure 12 and Figure 13 show the system inertia during the minimum demand period each year. Figure 12 includes the contribution from embedded generators which are theoretically capable of providing natural inertia such as Combined Heat and Power (CHP) plant, whereas Figure 13 excludes this effect. This can be viewed as a sensitivity between the best and worst case for each scenario since the proportion of embedded generation which is theoretically capable of inertia and is directly connected versus theoretically capable but converter connected (and therefore unable to provide an inertial contribution) is not precisely known.

Figure 12
Minimum System Inertia Including Contribution from Embedded Generation



Whole System Minimum Inertia

Figure 13
Minimum System Inertia Excluding Contribution from Embedded Generation



System inertia is already low during low demand periods and it is expected to decrease further under all of the scenarios. This is mainly driven by the drop in demand and conventional generation closures.

Slow Progression presents the worst case: whilst the initial reduction in inertia in Slow Progression is similar to Consumer Power and Gone Green, it stays low out to 2035 because of slower build of new synchronous generation, in particular nuclear generation, under this scenario.

Chapter four

4.2.3
Mitigating Options

There are two fundamental ways of managing the reduction of system inertia:

- Enhance the capability of the system to deal with the consequences of system inertia reduction:
  - Utilise fast response capability of wind farms, solar PV farms, and HVDC interconnectors (where technologies are suitable)
  - Utilise fast response capability of energy storage solutions (e.g. batteries, flywheels, compressed air systems)
  - New flexibility and fast response services from Demand Side Response (DSR)
- Develop new services which artificially increase the level of system inertia:
  - Utilise flexible thermal power plants to operate at low load or in synchronous compensator mode
  - Utilise flexibility in technologies such as wind and solar PV to manage short-term inertia issues (i.e. de-load these technologies to creating sufficient headroom for synchronous generators to operate).

These areas are further discussed in the Future Operability Strategy outlined in Chapter 8.

Rate of Change of Frequency (RoCoF)

4.3 Background

As highlighted above, generation and demand imbalance during times of low system inertia causes very rapid change in system frequency. This has the potential to unnecessarily trigger Loss of Mains (LOM) protection relays and other protection systems based on system RoCoF.

4.3.1 Impact on Operability

The RoCoF during the first second following a large generation infeed or load loss is an important parameter in order to assess the potential subsequent loss of embedded generation.

If the RoCoF during this initial period is sufficiently high to trigger LOM protection RoCoF relays on embedded generation then this could lead to cascading losses of large amounts of embedded generation.

High RoCoF causes frequency changes to occur very quickly. In the case where a very large infeed is lost and RoCoF is high, the frequency could drop below the lower frequency limit before a sufficient level of response has had time to respond to the event. RoCoF is therefore one of the factors which determines the amount and the speed of frequency response required to contain frequency within statutory limits following a large generator or infeed loss.

4.3.2
Assessments and Key Findings

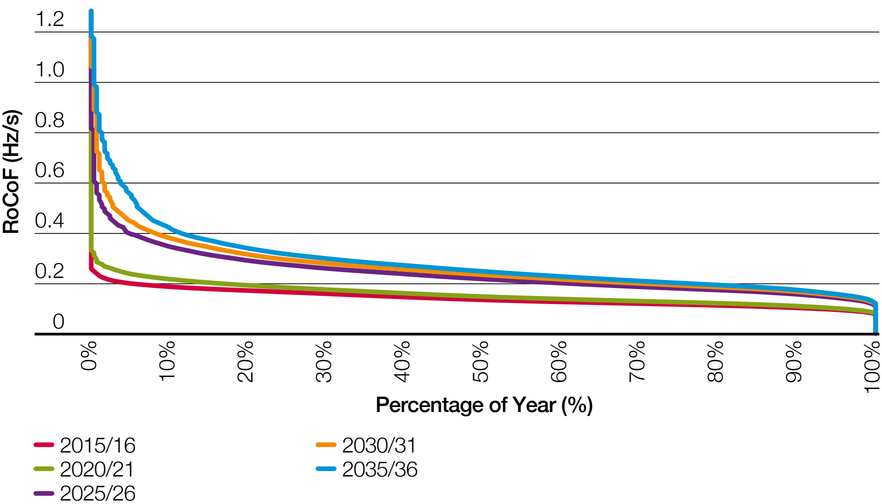
Figures 14 – 17 show the typical levels of RoCoF which could be experienced across a year under each scenario. No Progression is the only scenario under which the highest RoCoF across a year out to 2035 is expected to be within the new limits that will be implemented from 2016. All of the other scenarios are expected to see the RoCoF increase above the higher limit of 1Hz/s after 2030.

The RoCoF limit also determines the size of the largest single unit that can be providing infeed to the system at any given time – the SO needs to ensure that the loss of the largest single unit (currently the IFA interconnector when importing at 1000MW) will not breach the RoCoF limit.

Our assessments show that with a RoCoF limit of 0.5Hz/s (the lower of the limits to be implemented in 2016), the maximum infeed which can be tolerated without the risk of exceeding the RoCoF limit at any time throughout the year will fall below the current maximum of 1000MW in:

- 2030/31 under Consumer Power
- 2025/26 under Gone Green
- 2030/31 under Slow Progression.

Figure 14
RoCoF – Consumer Power



Chapter four

Rate of Change of Frequency (RoCoF)

Figure 15
RoCoF – Gone Green

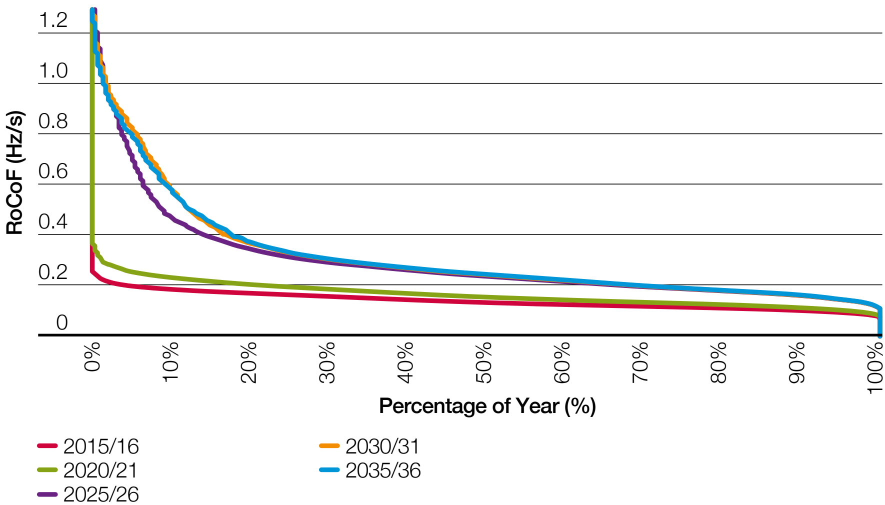


Figure 16
RoCoF – Slow Progression

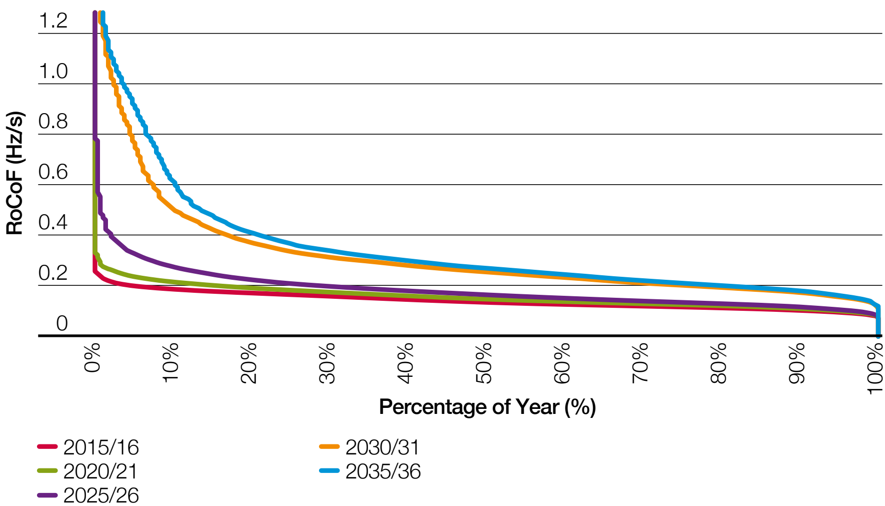
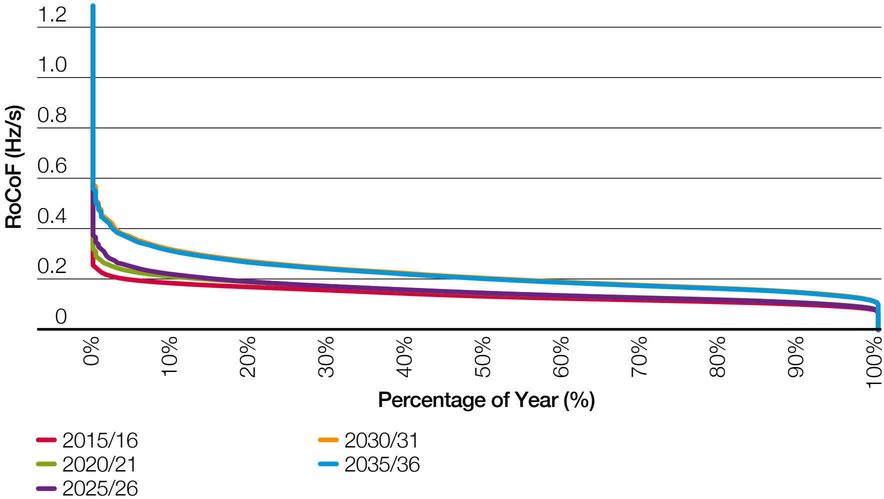


Figure 17
RoCoF – No Progression



4.3.3
Mitigating Options

In situations where a loss of generation might potentially cause a violation of a RoCoF limit one solution in use is to reduce the size of the largest generator output to below the level which would infringe the RoCoF limit if it was lost. Constraint of maximum infeed/loss for RoCoF reasons is an increasingly costly and ineffective solution for long term RoCoF management due to the increasing periods of potential limit violation. RoCoF relay settings are currently being reviewed for this reason.

The current operational RoCoF limit is 0.125Hz/s. The joint Grid Code and Distribution Code work group GC0035 was formed to assess and facilitate the setting change to 0.5Hz/s for synchronous generators and 1Hz/s for non-synchronous generators above 5MW. These requirements are expected to be implemented in 2016. The work group is currently examining further requirements for generators below 5MW.

Apart from the mitigating options set out above in the Whole System Minimum Inertia section, another way to mitigate the RoCoF risk would be to re-design the loss of mains islanding detection schemes. This could be done by using different input parameters, or by utilising, for example, Phasor Measurement Units (PMUs) to continuously monitor and compare generator phase angles against a set point[1].

[1] D. M. Laverty et al, "Loss-of-Mains protection system by application of phasor measurement unit technology with experimentally assessed threshold settings," in IET Generation, Transmission & Distribution

Chapter four

Frequency Containment

4.4 Background

When system inertia reduces, the system frequency becomes more sensitive to changes in supply and demand. This causes the frequency to fall more quickly following the loss of generation and a greater amount of backup response is required to stabilise the system and prevent the frequency from falling too low.

Frequency containment refers to a set of actions taken by the system operator to maintain the system frequency within statutory limits in the event of a sudden loss of generation or change in demand.

Frequency response providers are scheduled to alter generation or demand to redress the demand-supply mismatch caused by an unexpected event on the system such as the loss of a generator. The amount of frequency response scheduled for a particular time is predominantly dependent on the largest generator which could be lost on the system (the 'largest infeed loss'), the system inertia and the speed of frequency response available.

In the context of frequency containment, the grid in the future faces three main challenges:

- Reduction of system inertia giving rise to the rate of change of frequency
- Entrance of larger generation units which increase the largest infeed loss level of the system
- The displacement of traditional generation frequency response providers by technologies which need to be managed, designed or operated differently to meet frequency containment needs. The 'conventional response' level on the system at certain periods will therefore be insufficient.

This section discusses the results and implications of a number of studies undertaken to determine the frequency containment needs of the system going forward under the different Future Energy Scenarios.

4.4.1
Impact on Operability

Sufficient frequency response holding by the system operator is essential for operability of the power system. Generators can only remain synchronised to the grid if the grid frequency is controlled and remains within a narrow band hence it is essential to carry sufficient volume of response to manage such events as the loss of generation or demand.

An appreciation of potential future frequency containment needs provides an understanding of challenges in advance and allows a wide range of solutions to be considered before implementation.

4.4.2
Assessments and Key Findings

We have carried out assessments to determine the amount of frequency response required under each future energy scenario between 2015 and 2035 during both winter peak and summer minimum periods. By modelling the impact on system frequency of a sudden loss of the largest generator we can optimise the frequency response requirements. This determines how much response would be needed under each scenario to keep the frequency within the statutory limits.

It is assumed that traditional providers respond by ramping up generation between 2 and 10 seconds following the loss of the largest generator. If the running generation is insufficient to meet the frequency response requirements of the system then the amount of additional response from faster providers such as HVDC links, wind farms, solar PV, batteries and demand-side response is calculated. We refer to this as 'enhanced' response and assume it is delivered around 1 second following the generation loss and sustained thereafter.

Studies were performed at five year intervals for each of the four future energy scenarios from 2015 to 2035. In all of the winter peak scenarios, system inertia was sufficiently high for frequency containment to be of little concern. However, assessing the frequency containment needs of the system during low demand (in this case summer minimum) periods revealed a very different situation discussed in detail below.

The amount of primary frequency response needed during the summer minimum as a proportion of the 2015 requirements is shown in Figure 18. The results show that by 2030 under all four scenarios the amount of frequency response required will increase by 3 to 4 times from the current level. The increase occurs earlier under Gone Green because the largest infeed loss increases sooner than in the other scenarios due to different anticipated completion dates for new large generators which increase the largest infeed loss.

Frequency Containment

Figure 18
Summer Minimum Primary Response Requirements as a Percentage of 2015 Requirements

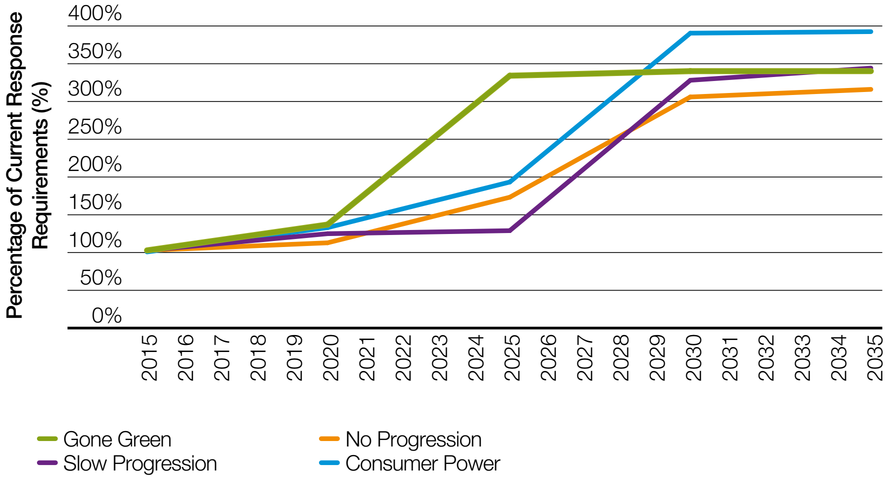
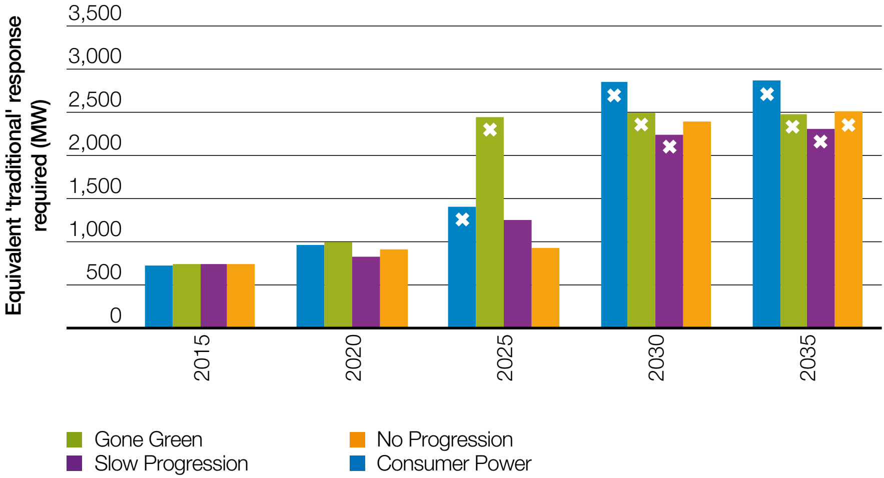


Figure 19 shows the amount of frequency response required to meet the largest infeed loss on the system in MW of traditional response. This refers to response deliverable between 2 and 10 seconds following the event.

In certain scenarios shown with crosses on the graph, it is not possible to achieve the total volume of frequency response needed from the generation mix on the system and alternatives must be found to make up the shortfall.

Figure 19
'Traditional' Primary Frequency Response Required in the Absence of Alternatives

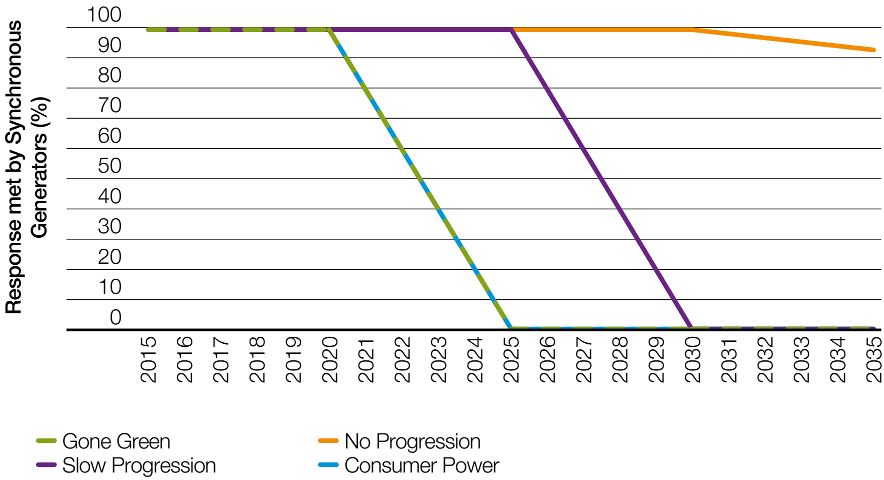


The reduction in system inertia, the increase in the size of the largest generator on the system and the increase in generation which does not currently provide frequency response are all factors which contribute to increasing response requirements over time. The scenarios with greater amounts of embedded and renewable generation (Gone Green and Consumer Power) require new providers of primary frequency response by 2025 and the other scenarios follow suit by 2030 (Slow Progression) and 2035 (No Progression).

The lack of synchronous generators which can provide primary frequency response scheduled to be running in each scenario is highlighted in Figure 20. All summer minimum scenarios except No Progression require frequency response to be met fully by new/alternative providers by 2030. This is under the assumption that wind farms and nuclear plants do not provide frequency response (as is largely the case at present) however as demonstrated in this document, there may be a need for this requirement in the future.

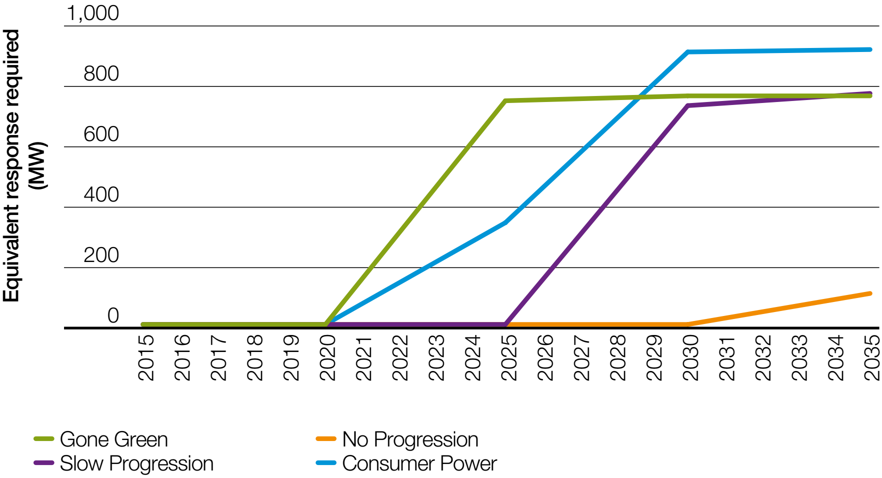
Frequency Containment

Figure 20
Percentage of Required Response that can be met by Operating Synchronous Generators



The amount of additional response needed if the alternative provider offers a faster response is shown in Figure 21. This is the amount of frequency response required in addition to what synchronous providers can offer and beyond a base assumption that 225MW of frequency response is provided by enhanced response providers. The faster a response provider can react and ramp up/down as needed, the lower the frequency response requirements of the system become. If the response cannot be as fast as assumed then the results in this figure would be higher.

Figure 21
Enhanced Response Requirements After Synchronous Response Has Been Used



There are several key points arising from the summer minimum assessments. Firstly, under all scenarios response requirements increase by approximately 30% - 40% within the next five years. Looking longer-term, under all four future energy scenarios a 3 to 4-fold increase in requirements is expected during summer minimum periods. Gone Green presents frequency response challenges most quickly due to the increase in the size of the largest generator before the other scenarios. For every 100MW increase in the size of the largest generator on the system the amount of frequency response required increases by approximately 280MW.

Increasing levels of embedded wind and solar reduce system inertia and displace plant which could have provided frequency response. For every 5GW increase in embedded wind and solar generation the amount of primary frequency response required increases by between 360MW and 460MW.

The assessments carried out in SOF 2015 for frequency containment highlight the importance of utilising the capability available in wind farms and solar PV plant at times of low demand and high production of these generation technologies. In doing so, a significant proportion of the response requirement of the system can be met by these resources which avoids the potential for curtailment or inefficient operational measures. Some of these measures, in addition to other options, are discussed.

Frequency Containment

4.4.3
Work in Progress

The Enhanced Frequency Control Capability (EFCC)/SMART Frequency Control project[2] is underway to develop and demonstrate an innovative new regional monitoring and control system for very fast response from multiple embedded providers as well as faster initiated response from thermal power plants. It aims to demonstrate the viability of obtaining rapid frequency response from solar PV, battery storage, and wind farms, and coordinate fast response from CCGT stations and demand side resources such as banks and water treatment plants. By developing an innovative technological solution in combination with commercial frameworks new generation technologies will be able to compete effectively with existing response providers in the balancing services market. The project will run from January 2015 to March 2018.

4.4.4
Mitigating Options

Based on the analysis above, it is expected that the challenge of securing adequate frequency containment measures to secure the system against the largest infeed loss will increase in future. The options to mitigate this challenge during the summer minimum include increasing system inertia, establishing new providers of frequency response services, developing faster frequency response services and utilising the flexibility of the synchronous and non-synchronous fleets by limiting the size of the largest loss.

To increase synchronous system inertia without having to curtail wind and solar PV, there are two options which must be considered:

- Using the flexibility in both synchronous and non-synchronous generation.
  – In the context of synchronous generation, it may be possible to operate thermal generators at lower output level allowing more of them to operate under the same load conditions thereby increasing the combined inertia of the system
  – Wind and solar PV generators offer great flexibility in terms of power output control capability which is most suitable for dealing with low inertia periods which coincide with times of high output from wind and solar PV plants. At those periods, the availability of wind and solar PV power is high and therefore they can provide greater flexibility to the system operator by offering new services. Compared with thermal generation, wind and solar PV plant offer a greater degree of flexibility in terms of power output level as this can be controlled with less restrictions when available

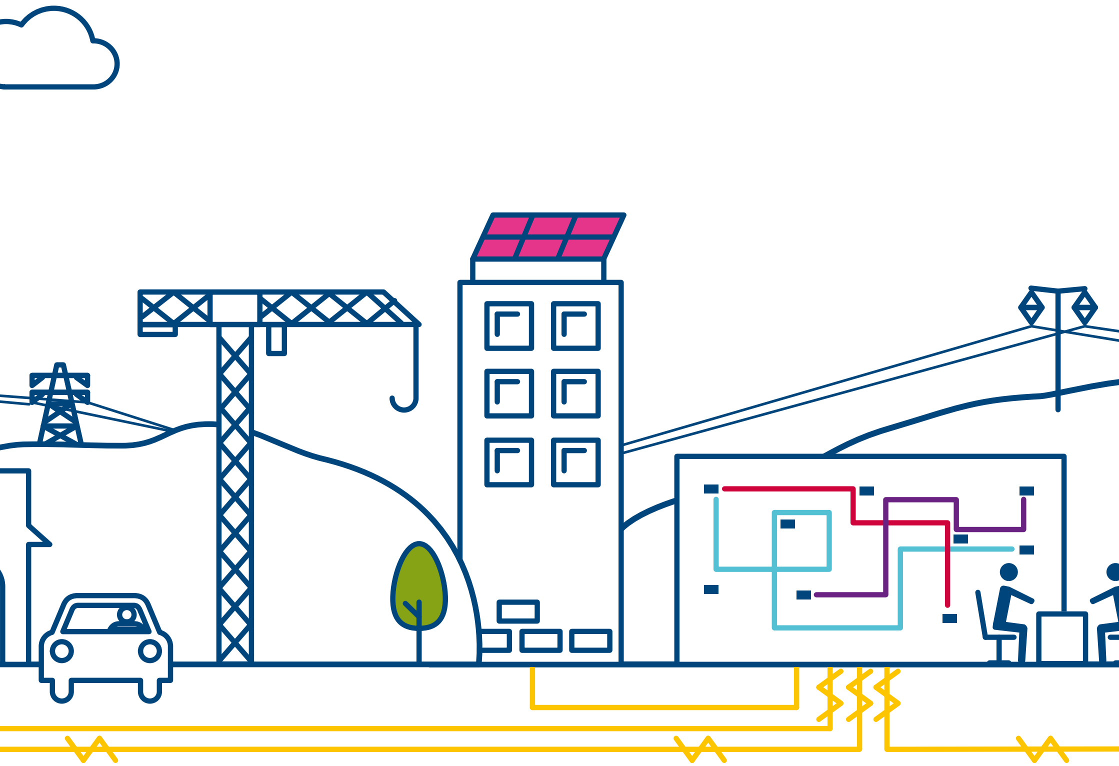
[2] National Grid Connecting, Smart Frequency Control Project [Online]. Available: http://www.nationalgridconnecting.com/The_balance_of_power/

- Technologies such as synchronous compensators or rotational stabilisers can contribute to system inertia. Synchronous compensators have been used in the past and subject to site assessment, could be retrofitted to decommissioned generators or introduced as new stand-alone devices.

During summer minimum periods there will be fewer traditional frequency response providers in operation on the system. Frequency containment services from new sources is one way to meet the needs of the system. There are currently no incentives for renewable energy plants such as wind and solar to run part-loaded in order to provide frequency response but this could change in future through new service provision arrangements. Additionally, many of these generators are connected to the distribution system which is beyond the visibility and controllability of the SO therefore this may create new opportunities for potential Distribution System Operators (DSOs) to consider these services when assessing business models. The use of renewable/embedded generation for frequency response would require some changes but has the potential to offer a significant source of response.

The development of new synchronous energy storage plants such as Compressed-Air Energy Storage (CAES) could offer frequency response services in the same way as the existing pumped hydro plants in addition to adding synchronous inertia to the system. Other types of energy storage such as flywheels and certain types of batteries could offer frequency response services which may be much faster than current providers. Faster response is more effective and so less response is needed if speed can be increased.

Demand-Side Management (DSM) involves using existing assets in a new way to respond to the needs of the system without impacting consumers. As discussed further in Chapter 7, wide-spread use of Electric Vehicles (EVs) may offer demand-side management potential for frequency containment.



Chapter 5
System Strength and Resilience

Key Messages

5.1
Key Messages

- Short circuit levels continue to reduce at periods of minimum demand between now and 2035/36 under all scenarios. Consumer Power identifies the most rapid decline over the next 10 years however Slow Progression represents the most significant degree of change between now and 2035/36
- Voltage and reactive power management is a challenge at present which is likely to significantly escalate in severity. It may be necessary to increase the level of reactive compensation on the system and voltage control from distributed resources such as embedded generation can significantly mitigate this challenge
- Synchronous generation decommissioning, particularly in the North East of England, North Wales and Scotland, in conjunction with rapid growth in embedded generation and diminishing operation of synchronous generation elsewhere highlights a need for additional Fault Ride Through (FRT) requirements from embedded generation and co-ordinated protection setting between TOs and DNOs. FRT must be considered from transmission and distribution system fault perspectives consistent with ensuring the stability of the total GB system
- A suite of new services and capabilities as mentioned in this chapter, when developed, offer greater system resilience and ensure the measures needed to maintain system strength and resilience are diversified and accessible at all times.

Declining Short Circuit Levels and Protection

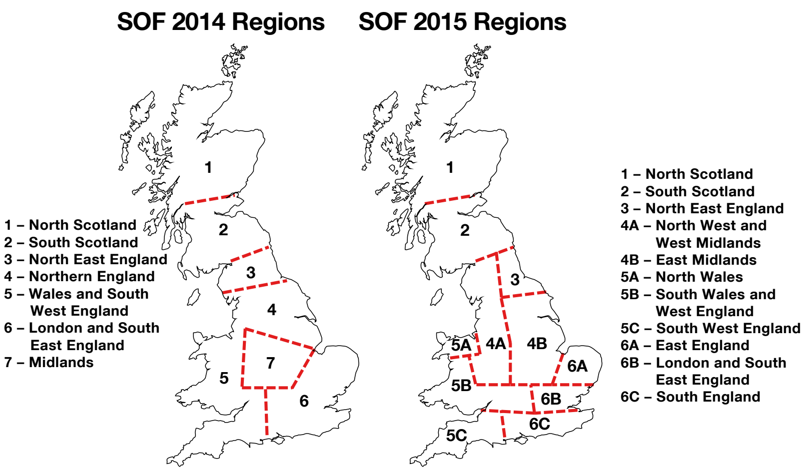
5.2 Background

Planning & operation to year round short circuit level is a routine activity of the GBSO, TOs and DNOs. Historically network investment and specification has mostly been done with peak demand for maximum fault level analysis. However, the minimum fault level has always had importance to protection design and operation and in the design of the dynamic characteristics of network element switching/response. Maximum fault level considerations continue to be reported within the Electricity Ten Year Statement, which further outlines the responses available and proposed for future change. In operability terms the range of actions for management of high system fault levels remains broadly unchanged. The changes within minimum fault level are both different in scale and in ramifications.

As such in SOF consideration of fault level relates purely to the trends and challenges relating to minimum fault level.

In the 2014 SOF, fault level variation had been evaluated for seven regions as in Figure 22 below. Whilst this was informative in last year's SOF, our stakeholders wanted further level of granularity in the changes of fault levels on the system. In the SOF 2015 we have further separated the system into 11 distinct areas, in order to show the trend for each area. The 2014 and 2015 results are shown together throughout this section for comparison.

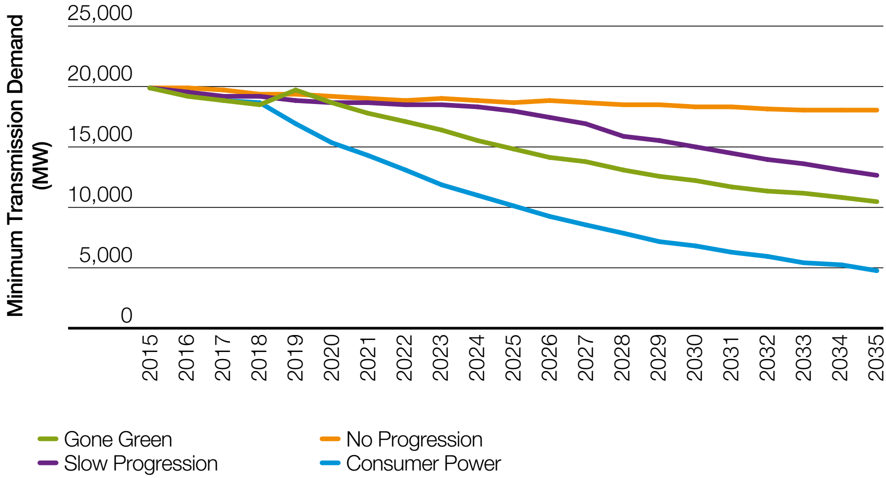
Figure 22
Short Circuit Calculation Areas for 2014 (left) and 2015 (right)



Declining Short Circuit Levels and Protection

The studies have been performed for the minimum transmission system demand period for each year of study as outlined in the FES 2015. These levels are summarised in the figure below which describes the total net demand observed at Grid Supply Point (GSP) interface. It should be noted that under each of the four scenarios, there is a transition in the minimum period from AM (approximately 5:30AM) to PM (approximately 2:30PM) as follows: Consumer Power 2019/20, Gone Green 2022/23, Slow Progression 2025/26 and No Progression does not transition.

Figure 23
Minimum Transmission System Demand at GSP Interface



For the assessments a level of network depletion typical to the minimum conditions has been adopted to reflect a base case for analysis. Short circuit assessments have been provided on a balanced 3 phase fault basis to a zero impedance grounding point.

5.2.1
Impact on Operability

Against the Security and Quality of Supply Standard (SQSS) and Grid Code, the GBSO, TOs and DNOs are not obliged to maintain minimum levels of short circuit strength on the GB system. Rather, we are required to ensure that the system in all defined conditions across codes and standards can operate technically and economically efficiently and securely at all times of the year. Short circuit level being a clear measure of system strength can impact future network performance indirectly across a range of areas subsequently discussed in the sections which follow, however, it most directly impacts the function and performance of the following:

- System Protection
- System Protection Co-ordination
- Induction Motor Start-up.

On the GB transmission system, protection is delivered by a combination of overcurrent, distance and differential protection devices, which in the case of a disturbance act to discriminate faulted elements of network and isolate accordingly from the wider transmission system as quickly as possible. The function and reliance of these protection systems upon fault level and initial fault current infeeds is different in each case (summarised in the table below). In all cases there is a dependency to grade (enable withstand or eliminate mal-operation in response to noise) or set (trigger levels and timeframes of operation) the protections based on a bandwidth of short circuit level assumption, including both maximum and minimum fault currents.

Table 2
NETS Historical Reliability of Supply

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. The bias may need to be set comparatively high at times of low short circuit level to avoid mal-operation.
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. This ratio however will be affected by the significantly different volumes of synchronous generation at peak and minimum demand and may drive additional settings.
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.

Declining Short Circuit Levels and Protection

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 the transmission system as well as other systems and those who interface with the affected circuits.

These bandwidths of setting and grading are initially set at the time of design and implementation of new protections and are then routinely reviewed and updated by the appropriate transmission or distribution owner over the life of those assets and circuits. The range of available settings and gradings are a function of individual protection system design consideration however and are limited by initial design choices. As the short circuit level declines, certain designs of protection may need to be replaced as the range of settings available on the device become less appropriate. Other protection systems, for example overcurrent protection, may no longer prove reliable in function.

Across transmission interfaces the timing, coverage, and design of protection systems is managed by an established commissioning process which operates on the basis of ensuring that overlapping protections have functionally or physically identical properties. The settings of protection are based on the first detection and response to the fault representing the protection system which leads to the least significant overall network depletion impact to all priorities. This ensures that for distribution system faults, transmission protections would not operate ahead of the clearance of these faults at a distribution level. As short circuit levels decline however, the ability to discriminate between the transmission circuits reduces in certain of the above protection types rendering such co-ordination more complex and more prone to risk of mal-operation. Furthermore, as described further in relation to the topic of voltage dips below, the timeframes of distribution system protections may increasing require acceleration in order to mitigate the impact of an extensive voltage depression at lower voltages presenting a broader system disturbance risk.

In these cases the TOs and DNOs concerned must identify the appropriate changes and their timing and establish new options for protection function at low short circuit level. Ultimately if it does not prove possible for network owners to respond to the changing minimum fault level, this will either mean that:

- The system becomes more vulnerable to planned contingencies leading to more extensive system depletion than normally designed
- Faults to be isolated from the GB system more slowly than planned, with consequences for wider network security in these cases
- A need for the System Operator to take steps to ensure that sufficient levels of fault infeed are available on the GB system, which in most cases would translate into a requirement for synchronous generator constraint.

Against the context of the decline in transmission system demand described in the 2015 FES, there is clearly a question where the GB System Operator may not be able in all cases to ensure sufficiently high fault level in future years by constraining generation plant given the limited balancing flexibility and volume available. As such, not only the energy market constraint costs which emerge from these actions but also the emergency actions that arise under Grid Code BC2.6. to instruct DNOs to disconnect levels of distributed generation that offsets demand at those times would have an impact on the costs, availability of the equipment and delivery of carbon offsetting ambitions as described within the FES 2015.

Large thermal generation, and to a limited extent other connections to the transmission system, will require upon start-up to start significant induction generation or variable speed driven motor loads in order to supply the site with auxiliary and generation unit power supplies. The start-up of such loads requires that for a short transient period an inrush current which is often between 6-10 times the normal load current of these motors to be supported. At a point of a low short circuit level, such inrush currents may be in danger of being mistaken for fault current, leading to tripping conditions, based on the protection settings otherwise required. Furthermore, there needs to be system strength, in general, roughly 3 times the scale of the motor infeed to ensure that the network associated is sufficiently robust to support that start up.

As short circuit level reduces, clearly the capability of the network to support individual or multiple simultaneous motor start-ups in close electrical proximity will decline. Where generation has adopted a two or more-shift pattern of operation where the generator is unavailable during low demand but starts up for certain high demand periods (or as instructed for balancing purposes), the decline in short circuit level may limit the ability of generators to respond as flexibly in this manner.

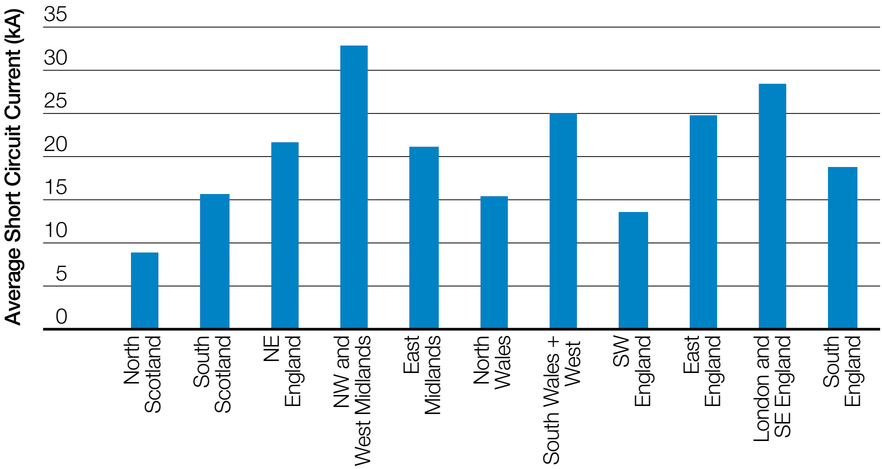
5.2.2 Assessments and Key Findings

The SOF 2015 approach to system strength has been to conduct detailed analysis of absolute fault level changes on the whole GB system in future years, complemented with analysis utilising a reduced GB system model. The rationale of this approach has been to use the full model to identify areas of specific protection system sensitivity and directly relate this to localised effects concerning both network and market participant availability. The reduced GB model, which excludes confidential third party information, is used to report on general system trends in a form suitable for external coordination, peer review and promotion of innovation.

Year by year, the system has been dispatched according to each future energy scenario and 3 phase-earth faults at each of the busbars covered by the 2015 study zone considered. The network has been set-up under AC load flow to be within acceptable voltage ranges and thermal flows compatible with normal operation. The network has been operated in typical intact configuration at times of system minimum (whether AM in the present year or PM in future years). This approach remains consistent to that followed under the SOF 2014 study and has been consistently replicated across full GB model and equivalent network model results. As expected this delivers current year fault level positions broadly comparable to those reported in the 2014 SOF. The current year minimum fault levels against the revised zones are detailed in Figure 24.

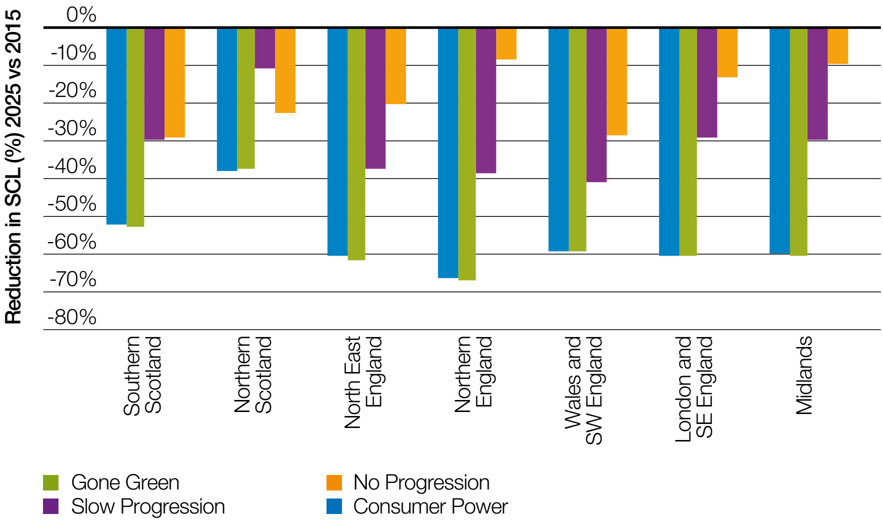
Declining Short Circuit Levels and Protection

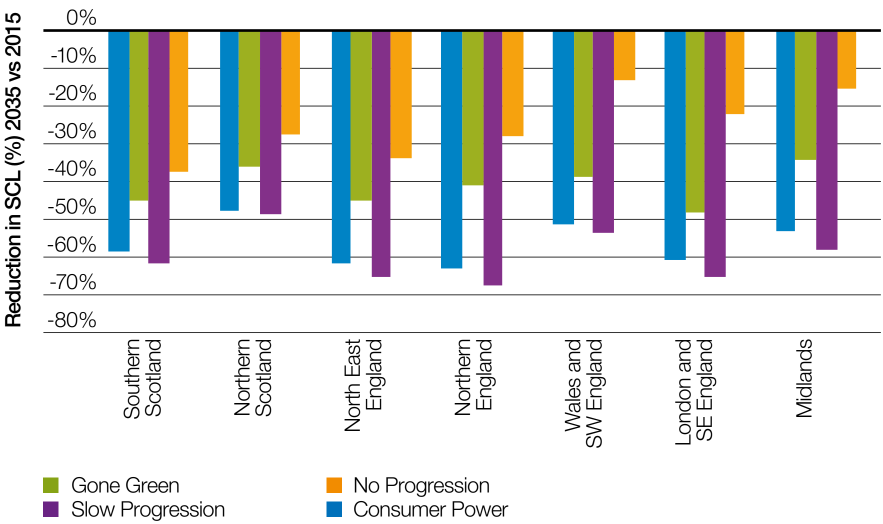
Figure 24
SOF 2015 Regions Short Circuit Level 2015/16



Regarding the evolution of the predicted system strength, Figure 24 shows the trend in fault level decline relative to the regions considered in the SOF 2014 regional presentation. Figure 25 shows the greater level of detail illustrated above for SOF 2015. Results are shown for the 10 year out (2025/26) and 20 year out (2035/36) datum average minimum fault level recorded in each region. It can be clearly seen that, in comparison with the changes illustrated in SOF 2014, over a similar timeframe the SOF 2015 results are significantly more onerous. In SOF 2014 the worst reduction in average minimum short circuit level by 2025 was some 55% in London and SE England. In SOF 2015 the reduction in that zone is now some 60% with other regions seeing far greater reductions of up to 68% (Gone Green 2025, Northern England).

Figure 25
SOF 2014 Regions SCL Decline 2025/26 (top) and 2035/36 (bottom) vs 2015/16





Declining Short Circuit Levels and Protection

The reason for the more significant reductions observed in our 2015 assessment can be readily attributed to changes that occur within the FES scenarios over this period. Under the FES 2015, the demand minimum of both Gone Green and Consumer Power scenarios has transitioned to an early afternoon minimum by 2025/26 corresponding with the effect of solar PV penetration. This leads to less space for plant which is not commonly base-loading today (renewable and nuclear) which must operate de-loaded under this demand level. There is limited offset, however interconnection exporting from the GB system may be able to provide some additional transmission system demand effect. It is clear that in areas where there is significant thermal plant today, for example Northern England, the effect of limited balancing space affording availability to plant removes their short circuit contribution at this time.

Figure 26
SOF 2015 Regions – SCL Decline 2025/26 vs 2015/16 Levels

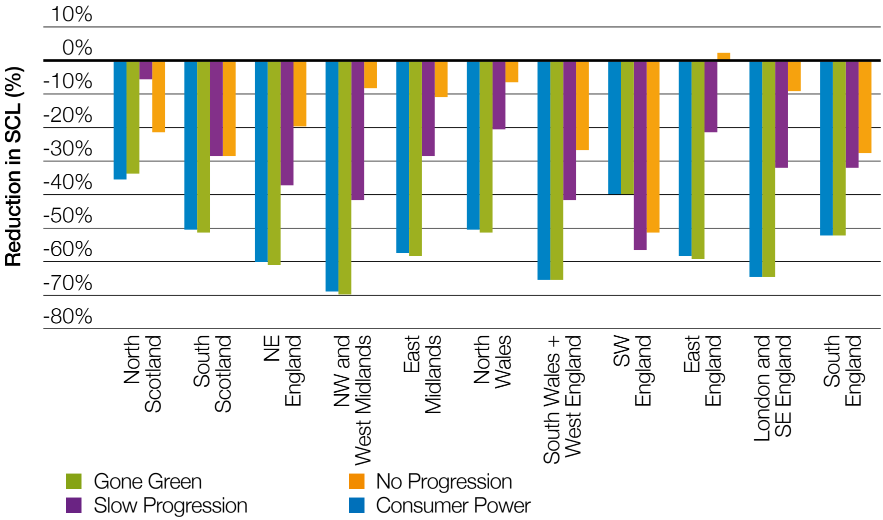
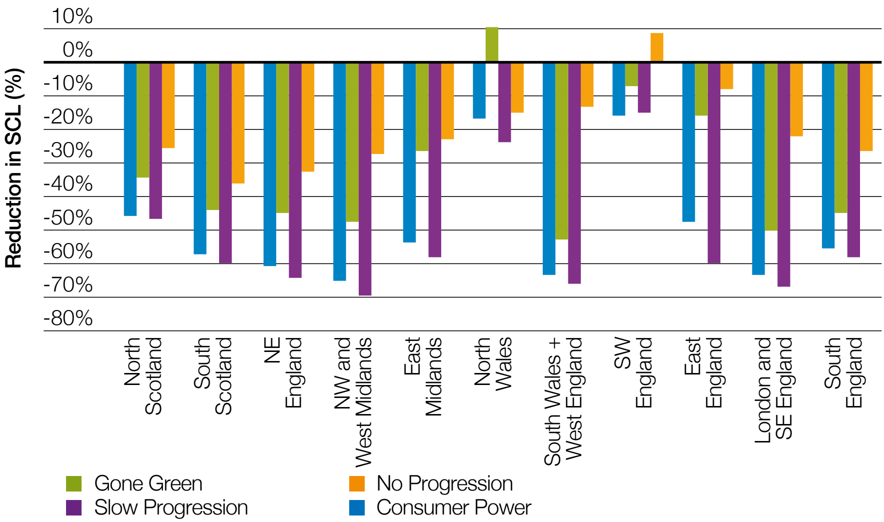


Figure 27
SOF 2015 Regions – SCL Decline 2035/26 vs 2015/16 Levels



By 2025/26, against publically available data used to develop the FES 2015, a programme of existing nuclear generation closures will further mean that remaining nuclear and renewable generation increasingly supports the minimum transmission system demand across the period 2025-2035. As described above, this causes the fault levels in particular areas to drop substantially. This can be most clearly seen in the new study regions in Figures 26 and 27 where drops in regional fault level can be readily correlated with the reductions in large plant in these areas. Equally the effect of new nuclear connections upon fault level can also be seen in these more detailed traces. For example, an increase in fault level under No Progression (partial recovery in other scenarios) is evident by 2035/6 in the south west of the system following the connection of 3.3GW of additional new nuclear generation at Hinkley Point C which arrests the initial reduction of up to 59% seen in 2025/26.

Large scale thermal power station closure and progressive unavailability, combined with the shift towards lower transmission system demands as predicted by FES 2015 coincidentally apply from 2019/20 onwards leading to conclude that the most significant onset of protection challenge will begin from this period. Based on the more granular SOF 2015 regional analysis, the areas of greatest challenge will be NW and West England, South Wales, NE England and London and SE England.

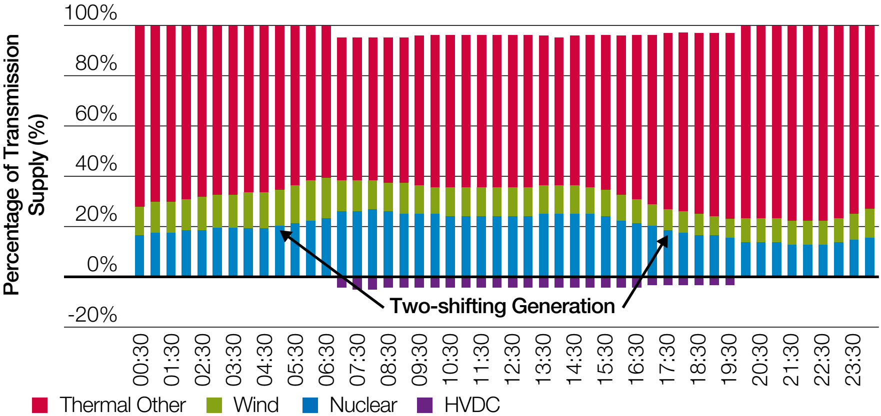
Due to the short circuit level dependability on large synchronous power station availability (especially nuclear in future years), planned station shutdowns and outages at these stations is expected to have a significant impact on wider system strength. Close co-ordination is therefore required between plant operators and the GBSO to ensure that outages are managed. It is necessary to account not just for local security considerations but also the wider impact of access pattern across the system.

Declining Short Circuit Levels and Protection

By 2035/36 the most significant FES scenario in terms of minimum fault level decline can be seen to be Slow Progression which can be readily explained by the future energy scenarios background. Slow Progression sees a slower new nuclear build programme to offset nuclear closures but the trend of falling transmission system demand continues such that there is otherwise very limited balancing space for other thermal contributions.

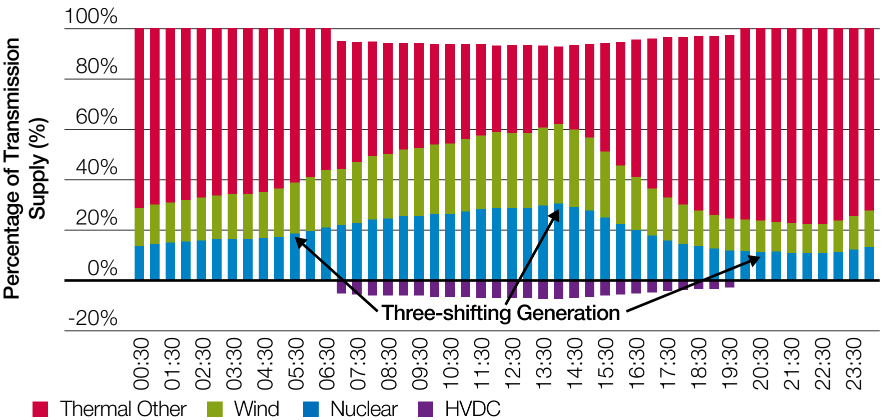
Our analysis shows that reductions in initial fault current, whilst pronounced, are less significant in general to those levels identified at time of break (with reductions of some 40% typical). This is not unexpected as, in addition to the change in fault contribution, the effective network damping on the system is affected significantly by the reduction of synchronous generators at this time leading to a lower ratio between effective network reactance and resistance (the X/R ratio). This in turn leads to a faster attenuation of fault current between initial current and that seen at RMS (100ms after the fault in this analysis). Relay action is further complicated by the fact that the fault current would be reducing rapidly within relay detection timescales, leading protection systems irrespective of setting to be more sensitive upon the relay function and performance and therefore at greater risk of potential mal-operation. In addition to impacting relay performance, this characteristic further impacts the complexity of practical setting of protections to ensure timeframes for operation can be effectively co-ordinated. In relation to generator start-up, we note that under 3 of the 4 FES scenarios (Slow Progression, Gone Green and Consumer Power) not only does the minimum load reduce over the time period considered, but also the shape of the load itself changes. Demand transitions from a well-established cycle of morning pick-up, daily plateau, evening pickup and overnight reduction to one of an extended trough in demand ahead of a steep evening pick-up. This is also explored in Chapter 7 of the FES through a balancing case study of the minimum daily load shape. Against that balancing position, Figure 28 establishes the potential points of future start-up from thermal generation based on the generation mix present at those times. This suggests that over time there will be an increasing number of on/off shifts from plant and that the volumes involved will be more extensive. Further on/off cycles arising as a result of available solar and wind generation across a given day may arise. The constraining on of generation for services cannot be precluded, nor can some degree of cancellation of on/off actions to meet this combination of needs.
These assume levels of de-loading of both the renewable and nuclear generation in response to the changing demand and a degree of interconnector export of power from Great Britain at these times.

Figure 28A
2020 Thermal Generation Shifting Against FES 2015 Balancing Case Study



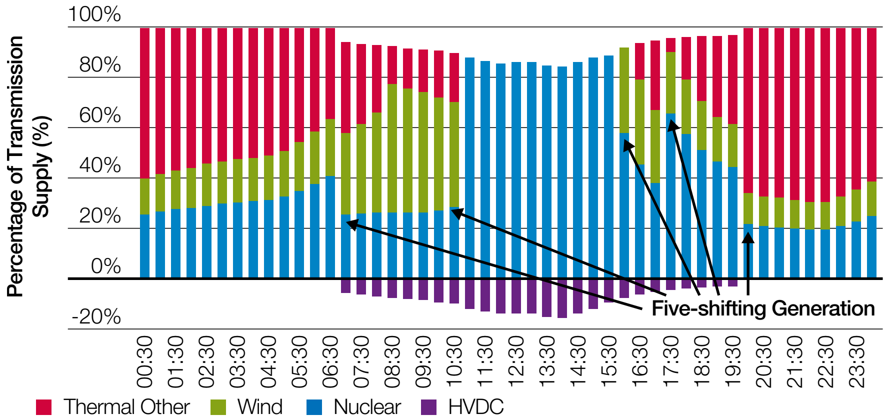
Across the current GB transmission system there are a number of examples of existing thermal generation two-shifting. It is clear that by 2035 there will be potential for periods of time of at least 6 hours during which there will be only nuclear, renewable and interconnector exports supporting transmission system demand. As highlighted above, at those times fault levels will be particularly low.

Figure 28B
2025 Thermal Generation Shifting Against FES 2015 Balancing Case Study



Declining Short Circuit Levels and Protection

Figure 28C
2035 Thermal Generation Shifting Against FES 2015 Balancing Case Stud



5.2.3 Work In Progress

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. The industry is also active in a number of initiatives which the GBSO is supporting or enabling which develop increased system monitoring capability in order to observe, trend and baseline maximum and minimum fault currents on the network. This will help in further improving the granularity and accuracy of present analysis offering the potential to minimise potential inefficiencies in operation at peak demand levels and further resolution of minimum system behaviours.

5.2.4
Mitigating Options

The process which manages the commissioning of new protections on both transmission and distribution systems and which supports interface co-ordination is a mature, well defined and effective process into which the considerations discussed in this assessment topic are being integrated.

Based on the data provided by the GBSO, currently, users routinely will review appropriate protection settings and equipment performance relative to maximum and minimum fault level changes and liaise with the GBSO where areas of impact or further consideration are required. However notwithstanding these points, it is clear from the assessments above that the scale of fault level change has increased and the timeframe has accelerated to different degrees based on the changes outlined in the FES. In response to this, research and development, technology changes, market changes and code changes can be considered. Different mitigating measures can be considered such as:

- Flexible Synchronous Generation at Low Load or as Synchronous Compensator
  Within the current Grid Code generators can currently define a Declared Minimum Operating Level (DMOL) no higher than 55%. We are however aware that some generators have capabilities of de-load to levels of 30% or lower, at which point their fault contribution would be available to support the grid. This option however would require some consideration of both technical and commercial code construction, together with developing an understanding of the service capabilities possible and required at such operating levels. Depending on the scale of capability and availability of this service however it does have the potential to significantly arrest the effects of declining SCL
- Increase Convertor Sub-transient Fault Contribution
  The existing convertor instantaneous overload capability is highly limited across the sub-transient period critical for protection relay initiation and detection. It is not clear what latitude may exist to achieve additional fault contribution across this period, or to ensure for a remote fault where local voltage decline may be less significant, that the converted sources supply additional fault contribution during this period. Any increase however is expected to be slight and is unlikely to be available without control system change on existing connections. Relative to peak fault level management, such arrangements also have the potential for adverse impacts where fault levels issues at peak demands are more marginal- as such this options complexity and limited benefit would result in it being a subject mainly for research at this time.

Voltage Dips

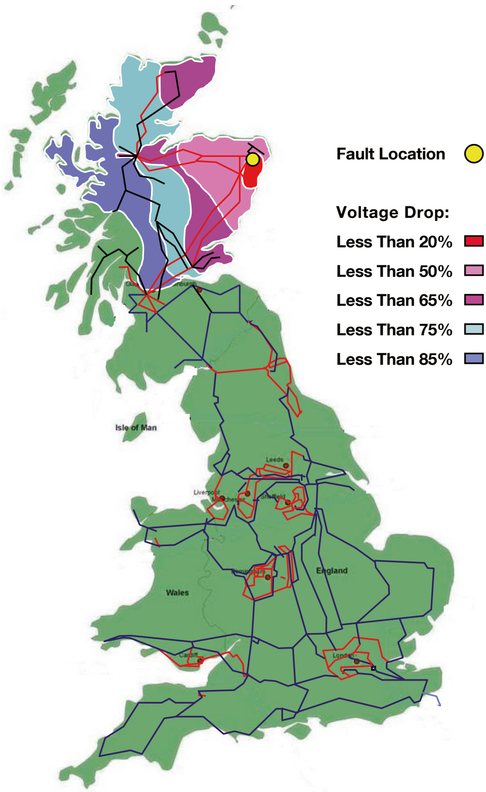
5.3 Background

A transient voltage dip is a short-term reduction in system voltage typically as a result of a short circuit, large machine start-up or switching/energisation. Given the meshed GB transmission network, there is always potential for the effect of a fault to propagate across wide areas of the system. Short circuit events have the most severe consequences on voltage dips and are often unpredictable and unavoidable (e.g. due to adverse weather conditions). Traditionally, given the predominantly synchronous generation connections to the network, 3 phase- earth connections were of principle impact however for Non Synchronous Generation the effect of unbalanced faults can be equally significant to their withstand and recovery. The extent and the duration of voltage dips observed need to be minimised due to their detrimental effects on generators and loads seeing the dip, achieved via the grid code specification above, and the action of the TOs to ensure that network recovery dynamics remain consistent within that specification to ensure network stability margins are maintained.

The depth and spread of the voltage dip are largely dependent on the strength of the grid, voltage control capability by other generators, and the electrical distance. Figure 29 illustrates a typical voltage dip contour describing the extent of impact.

The increase in NSG and closure of synchronous plants, combined with the general decline in Transmission System Demand observed in FES 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.

Figure 29
Voltage Dip Spread Example (2014/15 Fault at Peterhead)



Voltage Dips

5.3.1
Impact on Operability

As the short circuit level decreases, the size of the area affected by a voltage dip will increase. 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”).

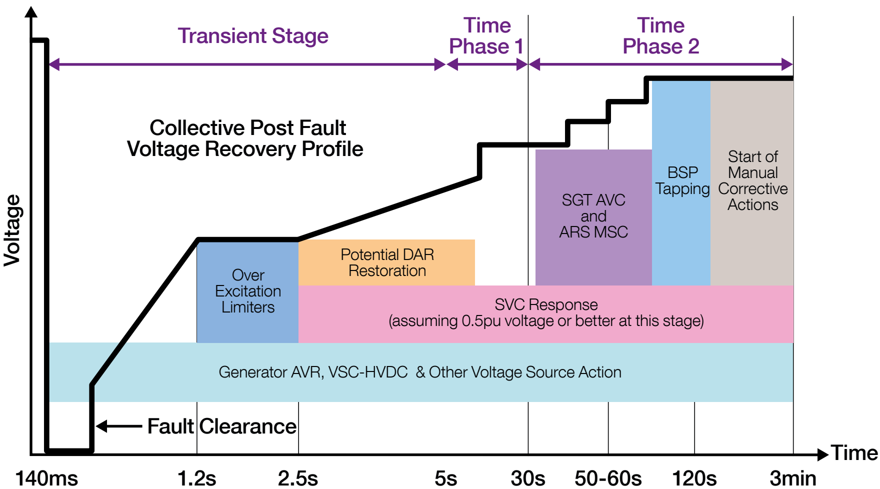
As many of the future voltage recovery support sources will be connected electrically far from the areas they need the support, the effective support of these sources will be lower. In addition, the installed capacity of embedded generators is expected to grow rapidly as per FES. These small generators currently do not have a strict Fault Ride Through (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 voltage dip, instead of supporting voltage recovery, large volumes of micro generation may disconnect. The 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 network.

The current draft version of the EU Requirements for Generators code11 has mandated FRT capability for smaller generators (potentially down to 0.5MW); internally National Grid is assessing the need case to aid such requirement, prior to any consultation regarding GB implementation of this code.

Historically the vulnerability to fault ride through has been focussed upon the effect of supergrid level faults, this is not unsurprising given that theoretically the voltage dip extent and severity should correlate directly with the strength of network and the differential in the availability of localised sources. However this assumption relates to a system which is expected to remain subject to distributed sources of fault infeed predominantly synchronous in nature in a comparatively strong network. Against the FES scenarios however a combination of a more rapid growth in NSG and a sharply reducing transmission system demand results in a far more severe condition which challenges this paradigm. In the scenarios considered, there are progressively limited sources of transient voltage support available, such that the impact of a distribution system fault to the transmission system has the potential to become more significant, analogous to the effect of a remote transmission fault depression. Unlike faults on the transmission system, distribution protection systems can potentially operate within 300ms-500ms clearance, given often more complex circuit configurations and the use of differing protection approaches to those employed and historically possible at transmission voltages. As such there is potential for these faults to appear differently to the family of curves considered in current grid code.

In respect of voltage, Figure 30 describes the critical role that reactive current injection plays in the response of the network to a voltage depression. In the initial instance of the fault, other than natural network response behaviours the TO and DNO assets initially provide very limited responses ahead of and following fault clearance against current specification, noting that certain OFTO assets as a result of their active role in offshore power park module fault ride-through at the onshore interface may provide additional support not shown. Where the initial voltage response of generation sources is unavailable there is a greater risk that following fault clearance further deterioration of voltage across a voltage collapse event might result.

Figure 30
The Collective Post Fault Voltage Recovery and Influencing Factors



Assuming that the above scenarios occurred and were not otherwise mitigated, the operator would need to take balancing action to minimise the scale of generation at risk due to the voltage dip. Action to modify transmission system power flow such that the consequence of the fault may be managed without wider impact would also be required. The operators ability to conduct these actions is dependent upon the visibility of embedded generation available at these times.

Voltage Dips

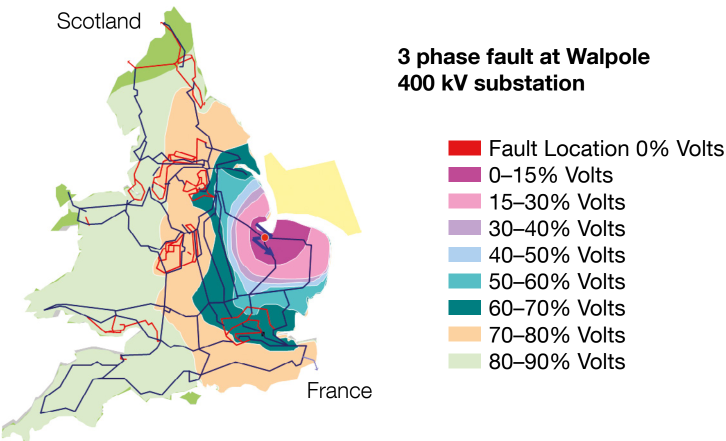
5.3.2
Assessments and Key Findings

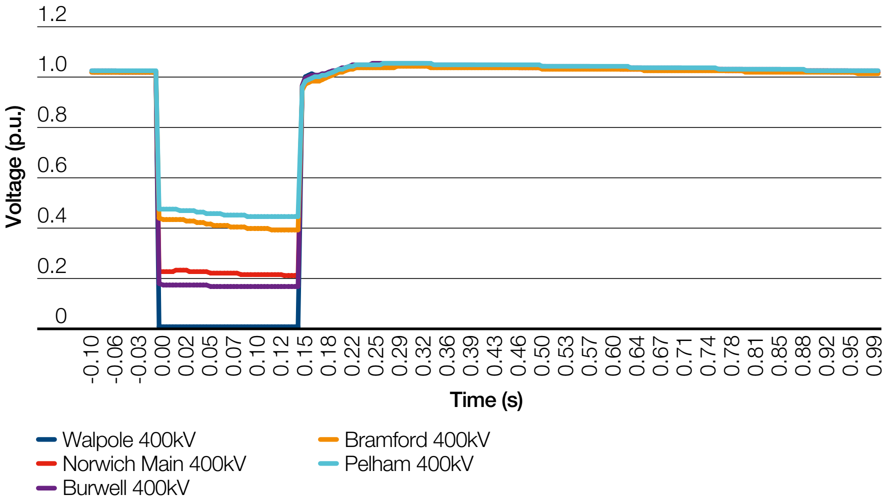
For SOF 2015 across the system a full GB system model has been modelled with an equivalent dynamic model of distribution system and embedded generation. Both generation and load were modelled with dynamic characteristics with typical voltage dependency applied to the load models together with appropriate modal characteristics. For 400kV faults a fault clearance time of 140ms has been applied with the retained voltage across the disturbance evaluated in time domain simulation. For 132kV fault consideration, a maximum fault clearance time of 500ms has been assumed, with these faults being modelled on DNO circuits close to the TO-DNO interface point. Both 3 phase-earth and single phase-earth faults are presented as illustration of the relative system dynamics. In each case it is assumed that the faulted element would not be permanently lost and that the network in broader terms remains unchanged following fault clearance

Two case studies are presented for Walpole and Sellindge sites. Both are locations which are broadly indicative of the general trends of increased NSG levels. In each case the 2015/16 and 2025/6 timeframes conditions are considered and compared for the Gone Green FES scenario, to remain consistent with the comparison adopted in the 2014 SOF assessments.

Walpole represents a site of high interconnection within the East Anglia region which over time sees an increase in NSG (significant offshore wind, embedded solar PV and embedded wind) and a modest growth in conventional thermal technologies. The figure below summarises the 400kV voltage dip position in the current year. From this figure, it is evident that over time an increased propagation of voltage dip emerges.

Figure 31
Current Network Effect of 3-phase Earth Fault at Walpole 400kV



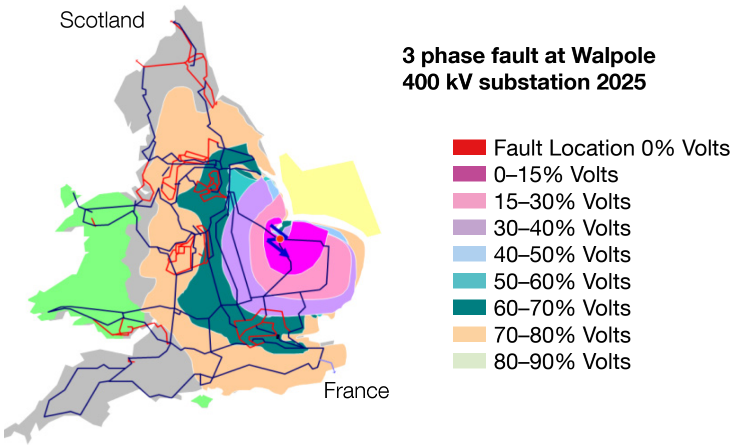


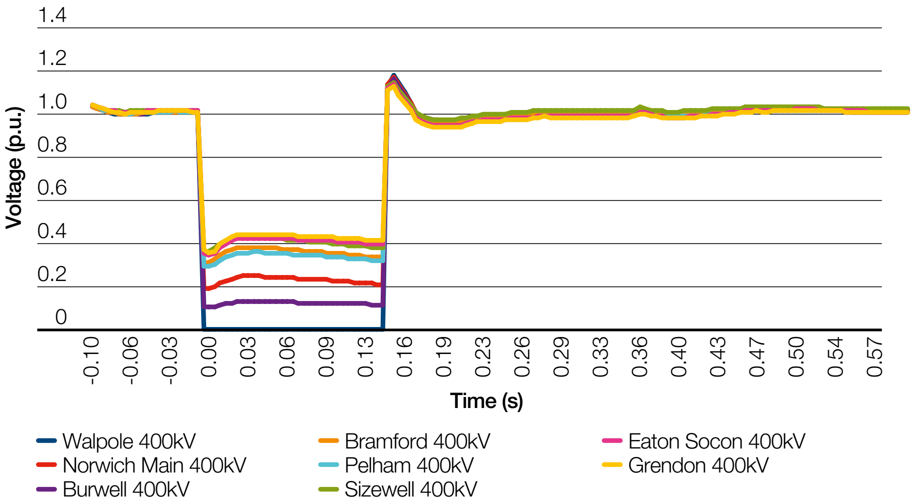
In the 2025 results, it can be seen that the degree of voltage dip observed for the same fault is wider due to limited local voltage control capability on the whole system. In addition, a temporary overvoltage of 1.2 pu can be seen to emerge in this condition for approximately 100ms. Such an overvoltage occurs as a result of STATCOMs and other convertors capable of providing a Mvar response (for example VSC devices) which supply reactive power support during a fault condition and charging intervening network elements such that a cumulative surplus shunt capacitive effect on voltage appears at the time of fault clearance.

This is then responded to by the associated controllers in the area. The estimates of embedded generation, in particular in the Gone Green scenario, are relatively modest, and their outputs at the time of this study are set to typical average high summer penetration levels (84% in the case of solar PV and 46% in the case of offshore wind generation, 19% in the case of embedded onshore generation). As such the overvoltage effects and the local impact on transmission system demand could be more severe against credible local planning conditions.

Voltage Dips

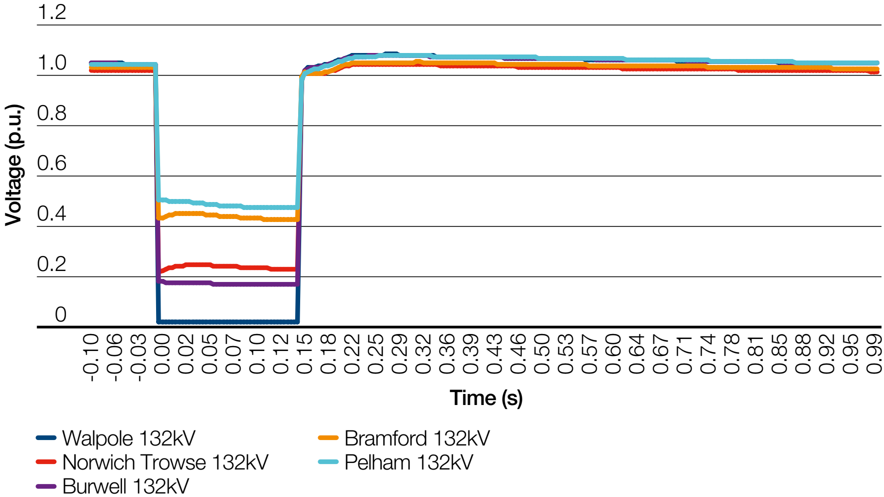
Figure 32
2025 Gone Green Effect of 3-phase Earth Fault at Walpole 400kV

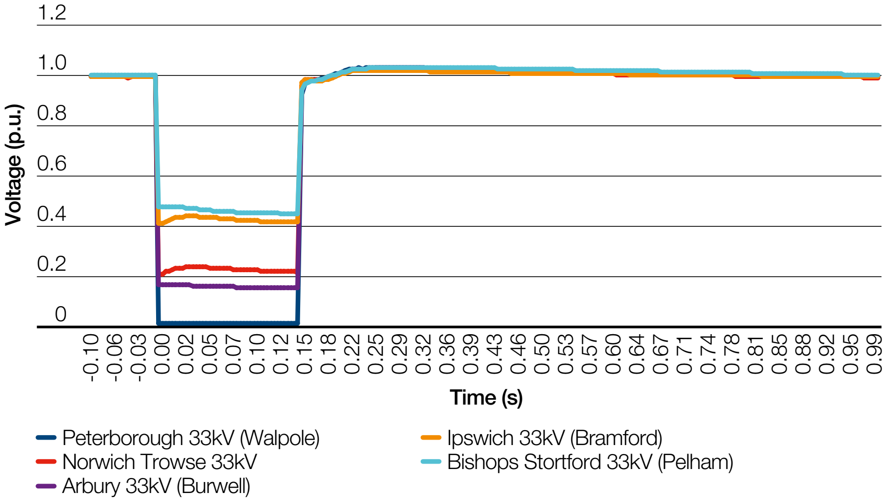




Turning to the translated effect of the 400kV faults as these impact the lower voltages, Figure 33 illustrates the effect on local DNO sites at 132kV and 33kV both at the Walpole Grid Supply Point and wider East Anglia area. In comparison, the impact of potential overvoltage can be seen in 2025 together with some residual oscillation in the recovery of the voltage across sites local to Walpole itself.

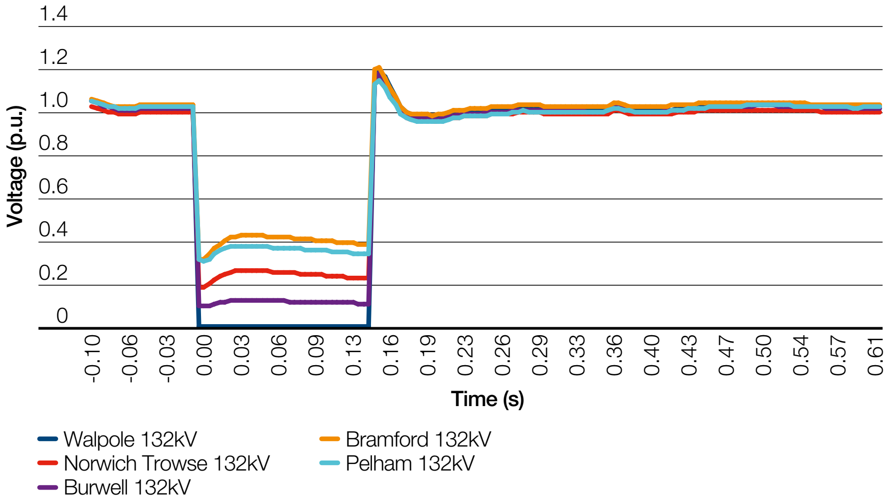
Figure 33
Current Network 3-phase Earth Fault at Walpole 400kV Transient Voltage Dip Event

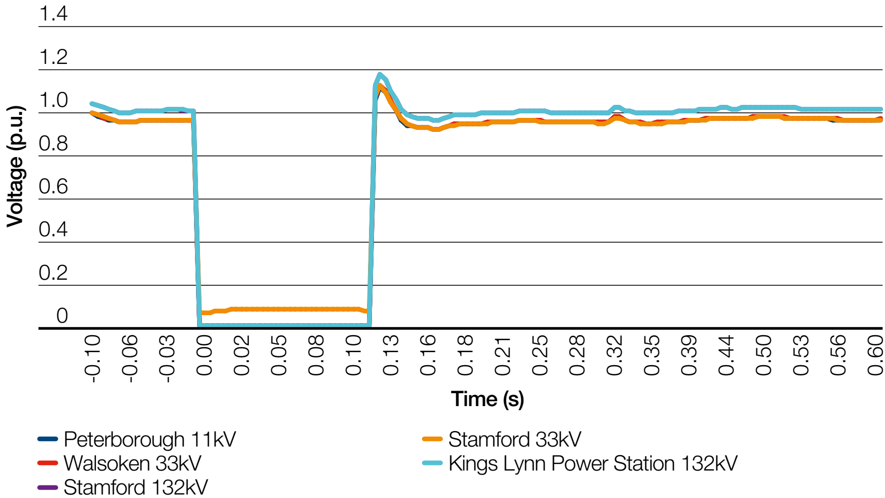




Voltage Dips

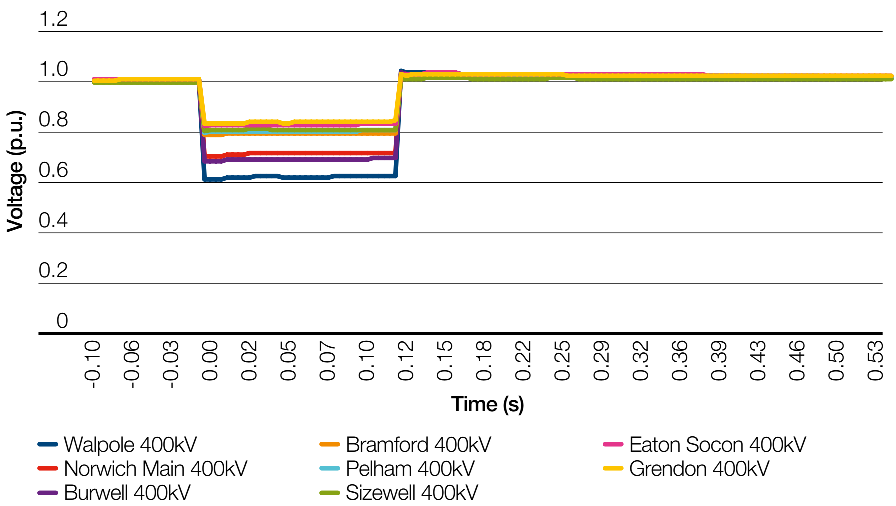
Figure 34
2025 Gone Green 3-phase Earth Fault at Walpole 400kV Transient Voltage Dip Event





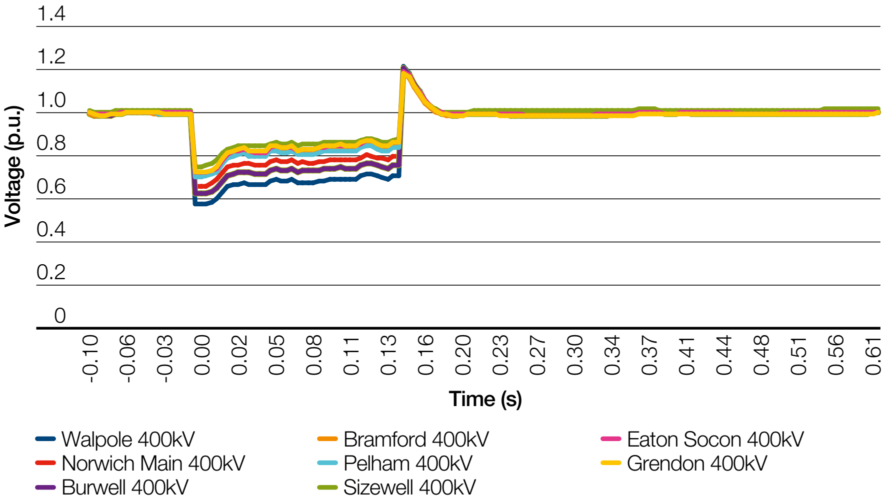
Figures 35 and 36 consider the impact of a single phase fault over the same timeframe. As can be seen below, in 2015/16 a relatively small overall drop occurs which does not penetrate the network significantly beyond the immediate East Anglia area. By 2025, not only the voltage dip observed is greater in depth, but also now significantly greater in extent. Other more distant devices can be seen to contribute with unbalanced reactive current, which consistent with the 3 phase event above leads to an overvoltage on recovery in the 2025 results. Equally it can be seen that oscillatory behaviour is emerging within the period of fault injection which persists to the point of fault clearance and has the potential to influence the quality of the voltage recovery of the system and device responses following the fault.

Figure 35
Current Network 1-phase to Earth Fault at Walpole 400kV Transient Voltage Dip Event



Voltage Dips

Figure 36
2025 Gone Green Single-phase to Earth Fault at Walpole 400kV Transient Voltage Dip Event



The figures below show the effect that the transmission system may see from a 3phase fault at the distribution level. These traces highlight that as the system strength declines, long duration faults approaching and potentially exceeding the capability required under a fault ride through event could be imparted upon the 400kV system as a result of a distribution level fault. In 2025 both a control interaction effect emerges during the fault response together with a double headed transient response which takes longer to stabilise.

Figure 37
Current Network 3-phase to Earth Fault at Walpole 132kV Transient Voltage Dip Event

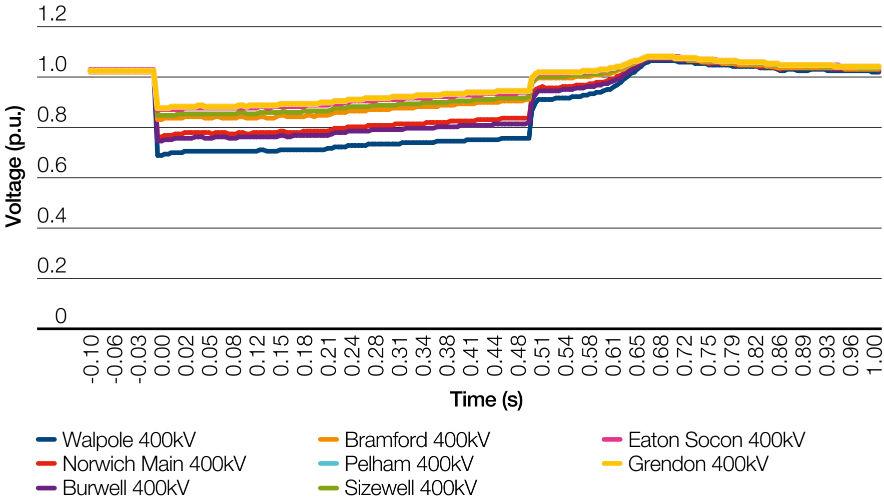
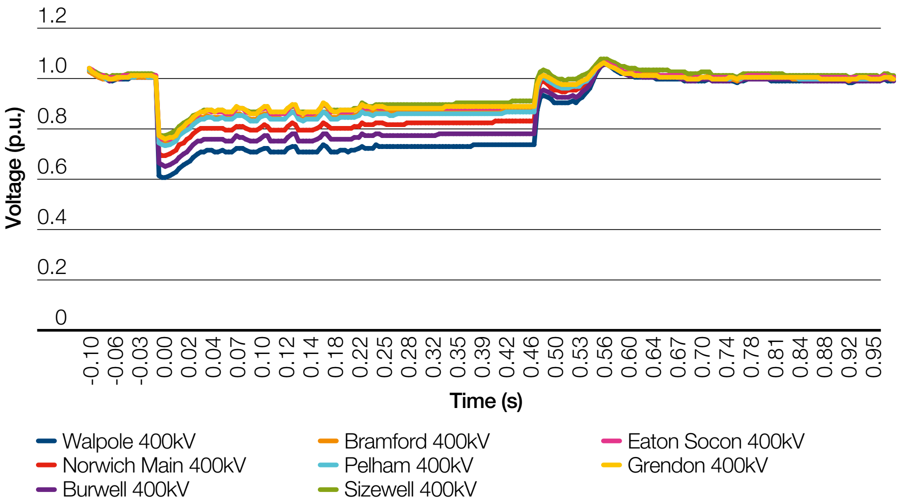


Figure 38
2025 Gone Green 3-phase to Earth Fault at Walpole 132kV Transient Voltage Dip Event

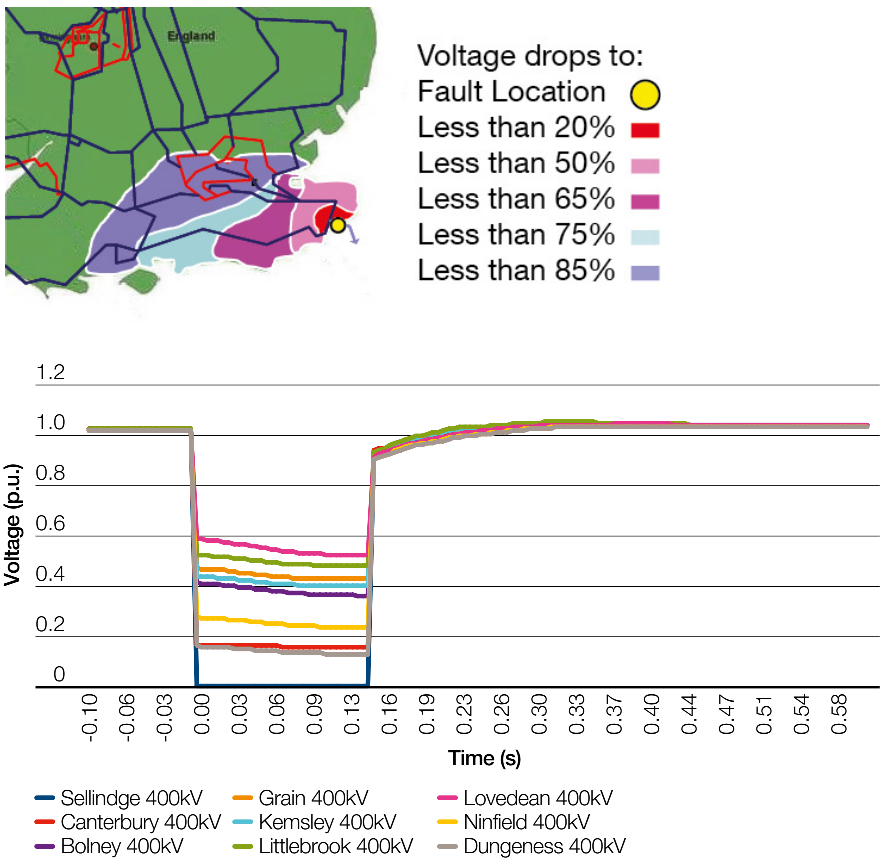


Chapter five

Voltage Dips

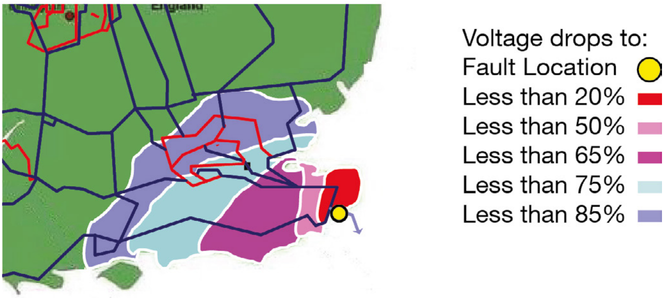
Conversely in the case of Sellindge, the area has historically been subject to the highest proportionate levels of non-synchronous generation on the system and is expected by 2025 to see additional transmission connected (interconnection and offshore wind) and distribution connected (solar PV and embedded wind farms) non-synchronous generations sources. Figure below shows that in this area, a far wider voltage depression occurs at transmission level in 2025 compared to 2015. Much like Walpole these depressions are replicated at the lower voltages of 132kV and 33kV respectively.

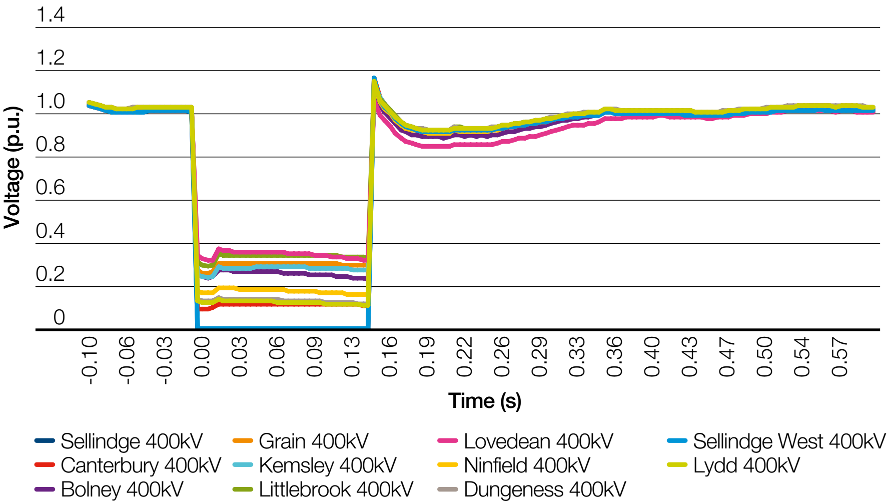
Figure 39
Current Network 3-phase to Earth Fault at Sellindge 400kV Voltage Dip for 140ms



Chapter five

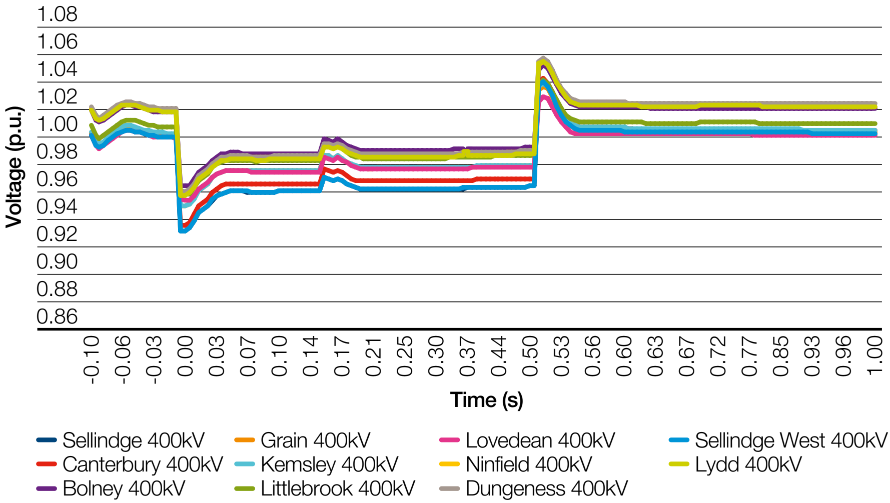
Figure 40
2025 Gone Green 3-phase to Earth Fault at Sellindge 400kV Transient Voltage Dip for 140ms





Voltage Dips

Figure 41
2025 Gone Green Single-phase to Earth Fault at Sellindge 132kV for 500ms



5.3.3 Work in Progress

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. The working group has now reported on a range of options and is due to present a proposal later this calendar year.

Robust assessment of voltage dip risk requires detailed knowledge of the DNO networks which is currently not available to the SO for all regions. The results of previous studies also rely on the accuracy of DNO assumptions and embedded generation forecasts (Grid Code work group GC0042 aims to improve this, however for the first year, a more limited subset of the data was required from DNOs and as such further refinement has not proven possible in this year based on the limited additional information provided under this channel).

5.3.4
Mitigating Options

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. Number of options which were previously discussed to increase the system strength will also help with minimising the impact of voltage dips (such as synchronous compensator, or utilising the flexibility of synchronous generators). In addition to previous options, the following options can be considered:

- Increased Voltage Support from Non-synchronous Sources:
  In demonstrating fault ride through minimum FRT capabilities it is currently unclear in the absence of appropriate market incentives that additional capabilities beyond the minimum service do not exist and could not be provided at particular times to provide additional support. Further user engagement via R&D in this area ahead of any broader market construction development should be explored-and the extent to its regulation/ specification. Such capabilities are expected to be limited in scale and may not necessarily correlate strongly with support in those areas of network most vulnerable.
- Fault Ride-Through Capabilities of Embedded Generation:
  Fault Ride-Through capabilities of embedded generation the analysis above indicates an existing vulnerability at across 132kV and 33kV connection points both local to the fault and geographically remote to the fault which increase in severity of exposure and extent over future years. Based on the current limitations of available combined transmission models it is not possible to determine whether deeper impact at still lower voltage levels exist but in the absence of any additional synchronous infeed support at those levels which may provide a degree of offset, the impact is otherwise expected to be that broadly similar levels of plant impacted. In order to limit the cumulative levels of risk in these cases FRT capability shall be sought via EU RfG code implementation to apply to all generation of 0.5MW and above, containing the risk volume and extent. Alternatives to this approach are limited by the balancing and frequency holding challenge that managing the scale of embedded generation loss would bring, or ensuring sufficient levels of dynamic sources of transient period reactive support are present in sufficient scale in proximity to the areas which are most vulnerable.

Voltage Regulation and Containment

5.4
Background

Voltage regulation is closely related to short circuit level with the later inversely proportionate to the scale of manifest voltage movement arising from instantaneous reactive power imbalances on the transmission system. The ability to regulate voltages tightly within defined limits is a principal indicator of power quality, given that unbalance and harmonic interferences represent supper-positions upon the AC voltage signal and as such are influenced by the ability to anticipate and contain absolute voltage magnitudes. These factors in addition to voltage step change encompass the subject of voltage management. 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; this is more fully discussed within the Electricity Ten Year Statement. We would however note from the FES 2015 scenarios that declines in reactive power absorption at the grid supply point interface are occurring across the year and are equally observed at peak.

In the current year, 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. Increasingly, as was experienced in last November, mild seasonal conditions can lead to extensions in this condition into other periods of the year also contribute.

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 43 illustrates the shift in averaged minimum (average of three minimum values) active and reactive power demand, and figure 42 illustrates the same trend in the ratio between reactive power (Q) and active power (P).

This reduction tends to be particularly noticeable overnight and across weekend active power minima at present. In the last few years reactive power demand reached its annual minimum value at approximately 4-6am in late May or early July, or at low demand periods around public holidays across the year.

Figure 42
Q/P Ratio for Weekend Minimum Demand Period

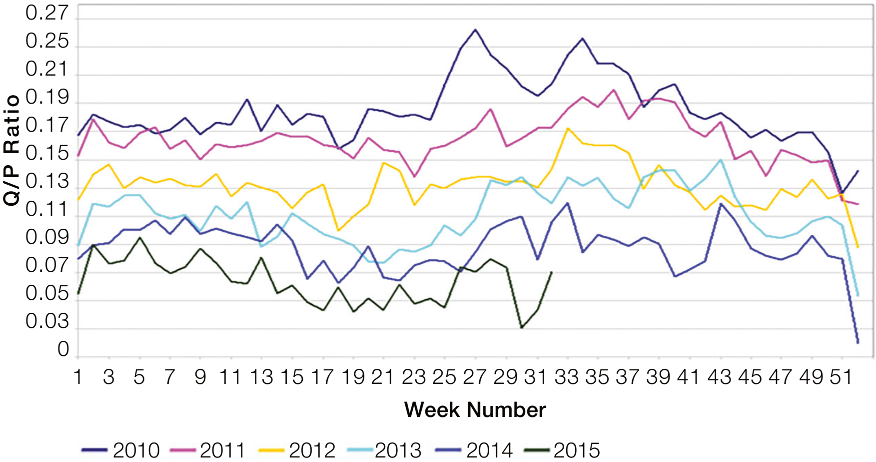
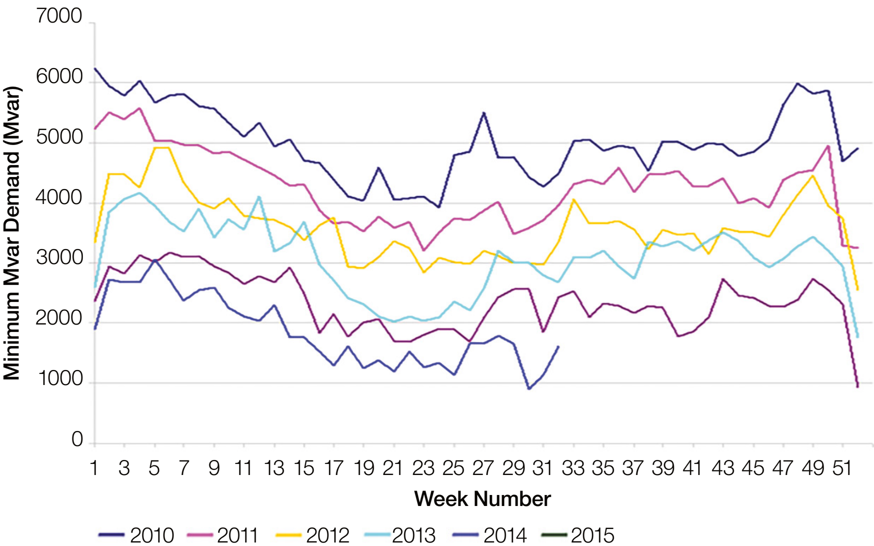


Figure 43
Actual Minimum MVAr Demand



Voltage Regulation and Containment

The exact reasons for Q/P decline are not currently clear and whilst investigation into the historic changes in reactive demand (most notably the REACT project) have been initiated nationally, international focus has primarily corresponded to investigations surrounding options to respond to the emergent trend only. As such there is limited literature to review in this area and many avenues of enquiry under consideration.

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 profile management
- 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 however broad trends can both be critiqued and extrapolated where analysis supports linkages with factors of change underpinned within the FES 2015 scenarios. 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 and many of its impacts may be confidently examined; in particular in Gone Green and Consumer Power scenarios we would expect a sustained decline in reactive power absorption at minimum demand periods across the network.

In addition to steady state voltage regulation, vulnerability to voltage disturbance; in particular towards Transient and Temporary Over-Voltage effects – are expected to increase over time as voltage containment of the pre-fault voltage becomes more challenging:

- Transient Over-Voltages relate to impulse driven disturbance and those relating to super-synchronous oscillations imparted upon the AC system oscillations, phenomena normally not lasting beyond a couple of cycles but which may be subsequently subject to both damping and travelling wave propagation/reflection effects. Examples of this category include switching, fault initiation (e.g. HVDC convertor blocking), clearing of electrical fault currents, and external risks, most commonly lightning strike events. In general the considerations surrounding Transient Over-Voltages relate to the characteristics of the impulse energy being considered, the withstand capability of equipment, flashover risks and insulation and surge arrestor grading adopted, and finally the quality of damping of the initial disturbance
- Temporary Over-Voltages relate to prolonged un-damped disturbances operating over multiple cycles and can result in post fault disturbances in reactive power balance to which a slow control response is applied but which lacks a sizeable initial impulse energy, or can relate to a sustained overvoltage which arises from a Transient Over-Voltage but persists beyond the initial couple of cycles of AC power following that event.

Existing approaches to TOV management via plant specification or particular asset or control solutions will therefore require review as the impacts of these factors evolve.

5.4.1
Impact on Operability

The overnight voltage profile in many areas is approaching the upper boundary of the operational limits. During 2012 at the beginning of the transmission system impact from high voltage management, some 165 events of high voltage were managed and mitigated by the operator. In subsequent years, having reduced consistently over 3 years due to enhanced operator actions and planning approaches, the incidence of such events have begun to increase once more and the extent of the rise is more fully reported in our annual system operator report.

It is important that this exposure is minimised since when prolonged, frequent exposure to high voltage can have the following impact:

- Flashover risks
- Asset overstressing and insulation breakdown
- Wound equipment over-fluxing
- Reduction of system monitoring equipment availability
- Risk of circuit breaker re-strike during de-energisation
- Increased risk of asset catastrophic failure
- Limitations in the post fault actions available to the operator involving asset switching.

Increasingly levels of generation are being constrained onto the system to specifically support overnight voltage containment. Figure 44 illustrates the increased costs to the operator of these MW constraints which have arisen as sources of dynamic support closer to demand centres have become less available and or have been subject to closure/ mothballing in recent years. Additionally typically some 100 Gvarh/ month of average utilisation at present over the April- October period is required to achieve such levels of containment once appropriately located resources can be made available to the operator, which again can be seen to grow over time.

Voltage Regulation and Containment

Figure 44
Increasing Cost of MW Constraint Due to the Effect of High Voltages

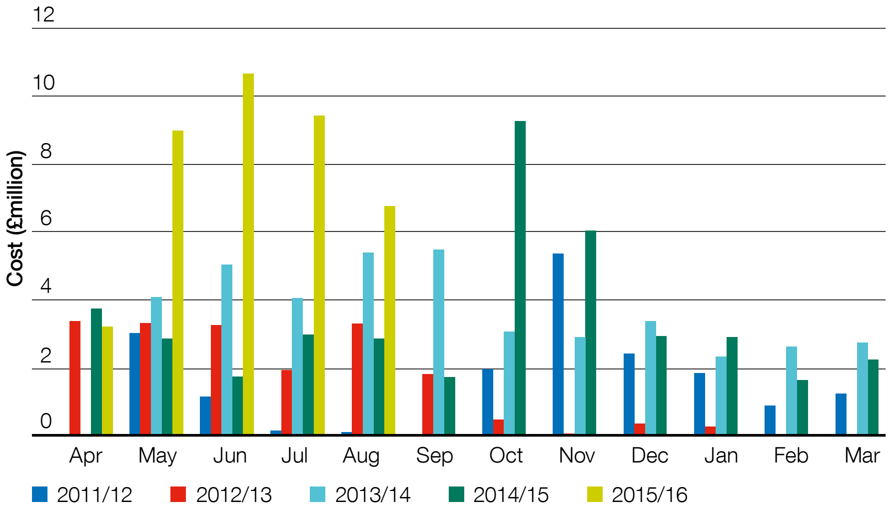
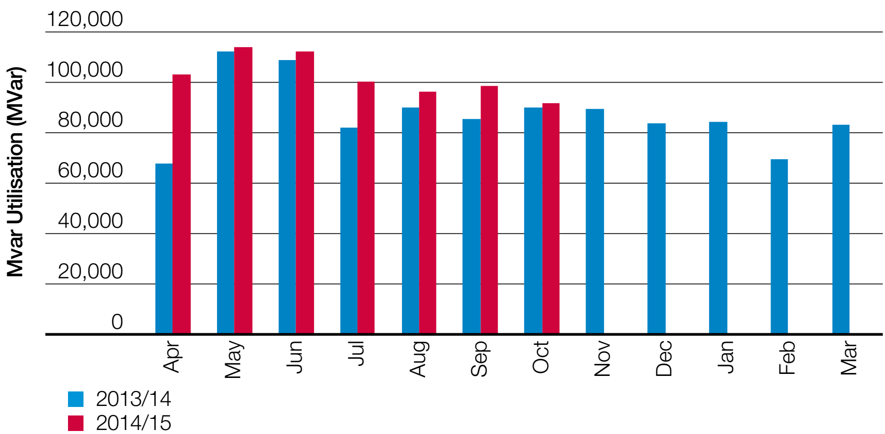
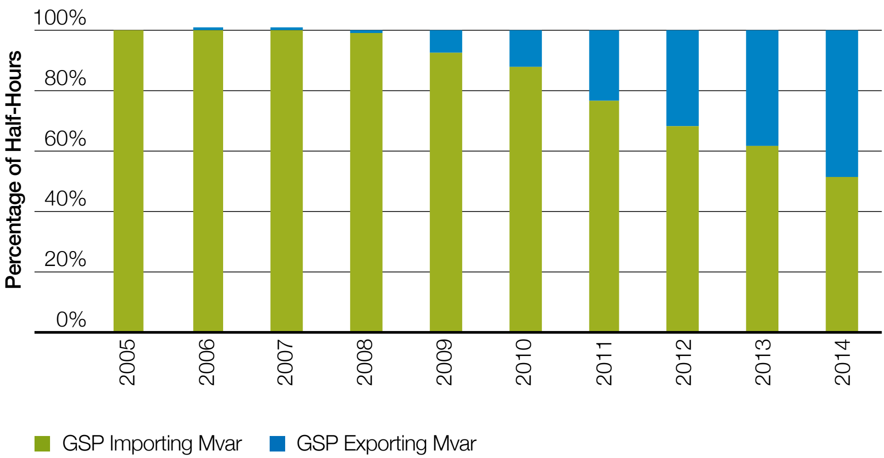


Figure 45
Mvar Utilisation Over Recent Years



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; as previously discussed within SOF 2014, the figure below illustrates the proportion of time the GSPs nationally have been net importers and exporters of reactive power in previous years.

Figure 46
Historic GSP Reactive Exchange



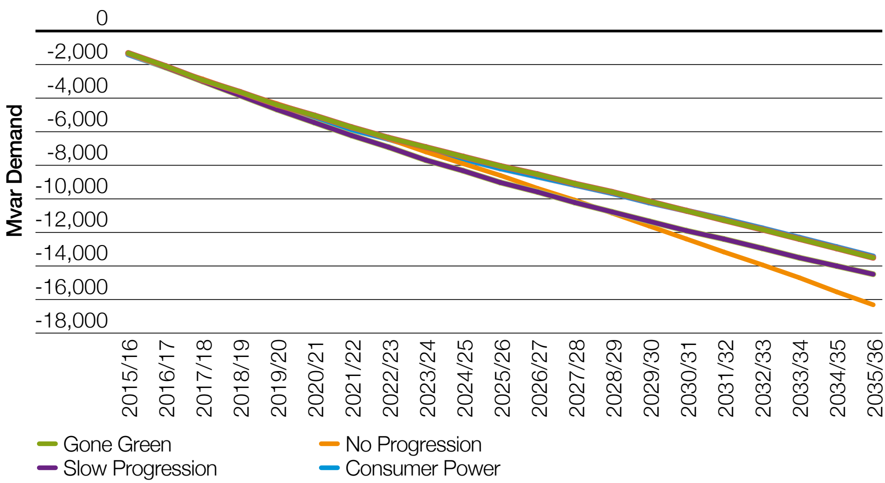
In 2013, the distribution networks were a net supplier of reactive power to the transmission system 39% of the time. This suggests that unless the decline in reactive power absorption is not arrested, the duration and extent of voltage containment issues will only increase, which is echoed in the findings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

Voltage Regulation and Containment

5.4.2 Assessments and Key Findings

Under the FES 2015 scenarios the minimum demand periods remain the most severe time of reactive power demand deficit (i.e. the lowest Q/P ratio) as shown in figure below. We can observe that the increased net tendency towards reactive power export is at its most severe within the Consumer Power scenario where the combined impacts of high levels of energy efficiency and the most pronounced scale of embedded generation combine to most significantly collapse and reverse the reactive power demand.

Figure 47
Projected GSP Reactive Power Exchange



The regional breakdown in the reactive power exchange described above is illustrated across all scenarios in figures below. They show the GSP groups which at different years, and scenarios become MVAr exporting.

Figure 48
Projected Reactive Power Exchange Geographically in 2025

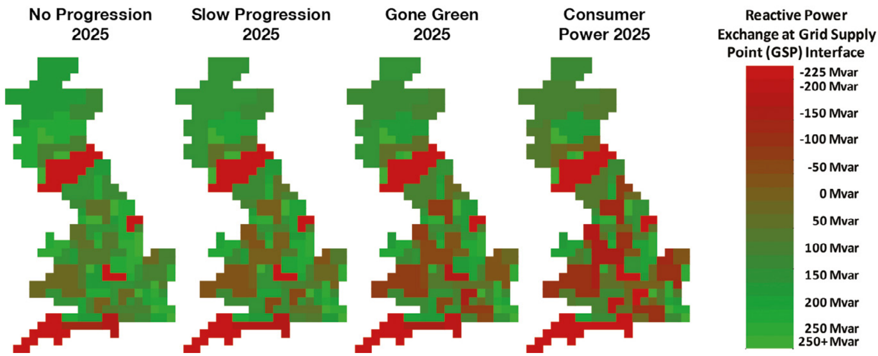
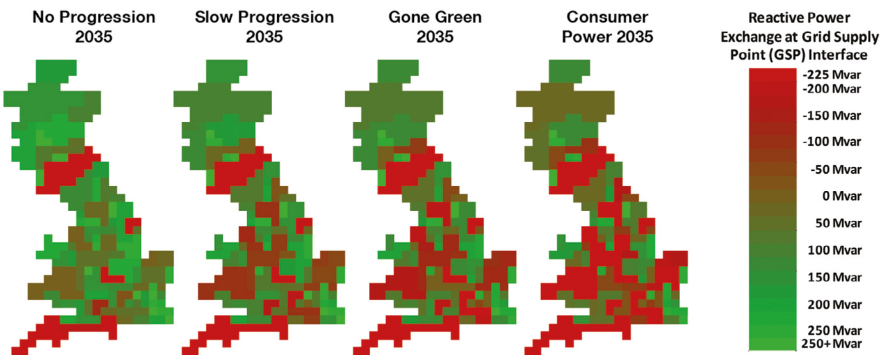


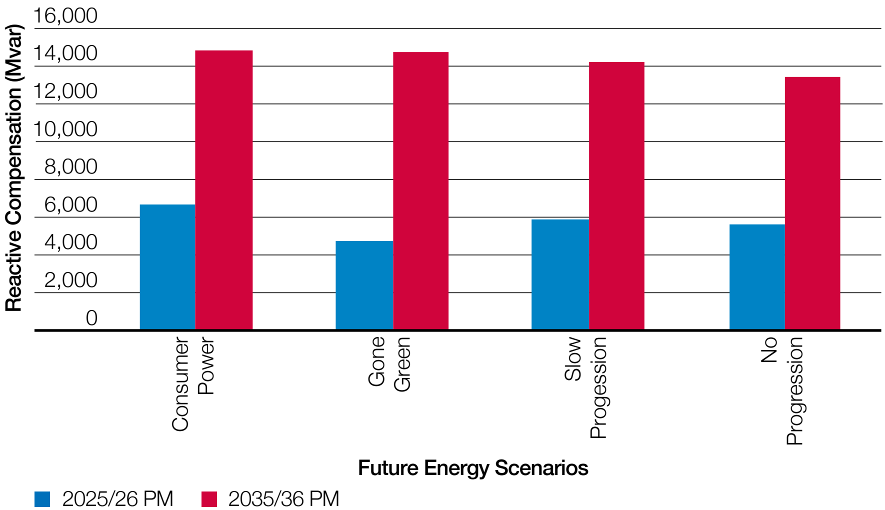
Figure 49
Projected GSP Reactive Power Exchange Geographically by 2035



The regional breakdowns above illustrate the impact of new embedded generation power injections at or close to unity power factor on increasing the reactive power export at GSPs. The levels of transmission connected compensation required in future years to contain the transmission voltage have then been identified and optimised for intact system operational conditions. In this analysis new embedded generation has been once again included at a unity power factor. This assessment concludes that, in addition to the 2.86Gvars of compensation already in delivery and due to complete in 2017, up to a further 14.8 Gvar of compensation (under Consumer Power scenario) or other control measures would be required in order to maintain transmission system voltage levels with planning standards in future years.

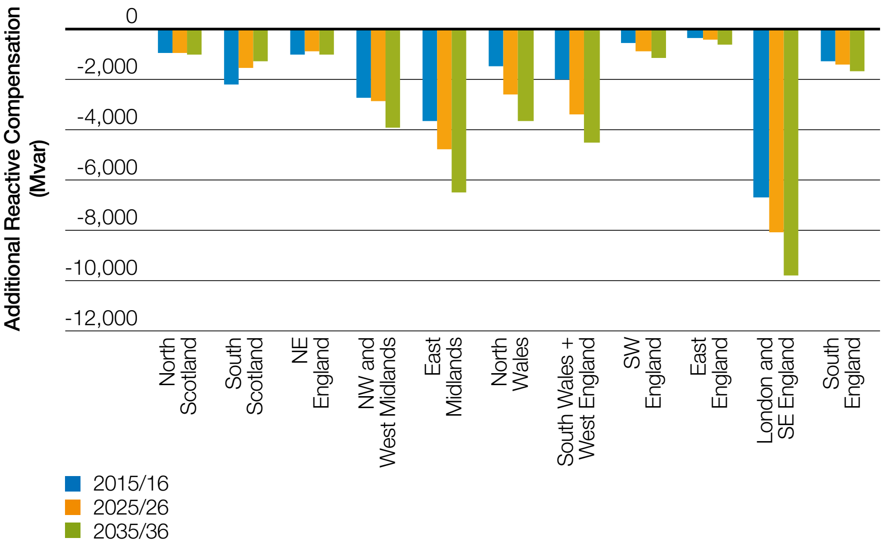
Voltage Regulation and Containment

Figure 50
Reactive Compensation Required to Contain Transmission System Voltage



Figures 50 describes the requirements for compensation to restore transmission system voltages to within planned regulating limits across the next 20 years. These levels of compensation placed at transmission voltage cannot not fully address the broader impacts of high voltage observed within distribution system. The level of compensation requirement shown here however is unprecedented in its scale and would require a whole industry response employing a variety of approaches and services to achieve this volume of effect in a deliverable and operable manner. As can be seen in Figure 51 the compensation is not evenly spread across the transmission system and some areas see greater need for reactive compensation. As with short circuit level some of these changes can be correlated with areas most closely associated with the decline of availability of synchronous generation however it equally and more strongly correlates with areas of most significant Q/P decline at the interface. By 2035 under all scenarios other than No Progression, the reactive compensation requirement in Mvar will exceed the transmission system demand in MW.

Figure 51
Regional Breakdown of Additional Requirements for Reactive Compensation



Voltage Regulation and Containment

5.4.3
Work in Progress and Key Findings

The challenges surrounding future voltage control are well communicated across the industry with standing Industry Workgroups, research and development work and manufacturer engagement. In summary:

- Project REACT: Under the REACT investigation, the project concluded its 2 year project of analysis into those factors contributing towards Q/P decline and areas of potential forecast improvement. The key findings from this work have been:
  - Higher susceptance of circuits within of the distribution system which has increased the charging gain of the distribution networks
  - Correlation between National Grid and DNO metering over a 7 year period has highlighted that the trend in reactive power decline can be seen within DNO system flow as well as at the transmission voltage and as such there are a range of forecasting approaches that can be related from the lower voltage load and generation balance to the forecast of interface behaviour
  - That reactive power offsets at higher distribution voltage levels are most effective against the decline and that subject to placement, value of up to 1.2 times the transmission interface offset can be identified in strategically citing mitigation measures.
- The Energy Network Association (ENA) High Voltage Working Group: The ENA initiated a high voltage on 13th May 2015. This group has concluded its technical examination of the relative merits of an array of responses across transmission and distribution levels to Q/P decline, is currently examining the commercial and regulatory enablers for such responses and is due to publish its findings following stakeholder consultation early in the new year
- ENTSO-e Demand Connection Code (DCC): The EU Demand Connection Network Code is expected to be fully implemented by 2017. This, subject to a cost/benefit analysis, may potentially restrict the reactive power exchange at the GSPs. An implementation group which acts as a subgroup of both the Distribution Code Review Panel and the Grid Code Review Panel has been constituted and is working on the requirements associated with GB system adoption of arrangements defining and managing reactive power exchange definition within a range of anticipated active power transfers at the Transmission- Distribution system interface
- South East Smart Grid: The South East Smart Grid project is a TSO/DSO project investigating the better use of shared resources at transmission and distribution system; with particular focus on the measures available for voltage management. This project will effectively allow utilisation of the resources at all voltage level, including the potential role for DSOs to provide services to the system.

5.4.4
Mitigating Options

The measures previously discussed to increase the system short circuit levels and voltage dip resilience, in addition to transmission solutions (i.e. installation of reactive power compensation beyond the 2.86Gvar already invested by TOs between now and 2018) all enhance the steady state voltage control capability. In addition the role of DSO services are discussed here in providing greater capability in managing the network voltages.

- DSO Services: In the context of voltage control, the reactive power exchange between the transmission and distribution interface points is related to number of factors, which some can be controlled if the DNOs have the capability to actively manage their networks, and the components. This includes:
  - Demand Side Response for voltage control via contracting for embedded generation de-loading, or directly to provide reactive power
  - Services from the DNO’s network components (transformers tapping, tap staggering, circuit switching, or installation of reactive compensation devices at the DNO network).

Power Quality

5.5 Background

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:

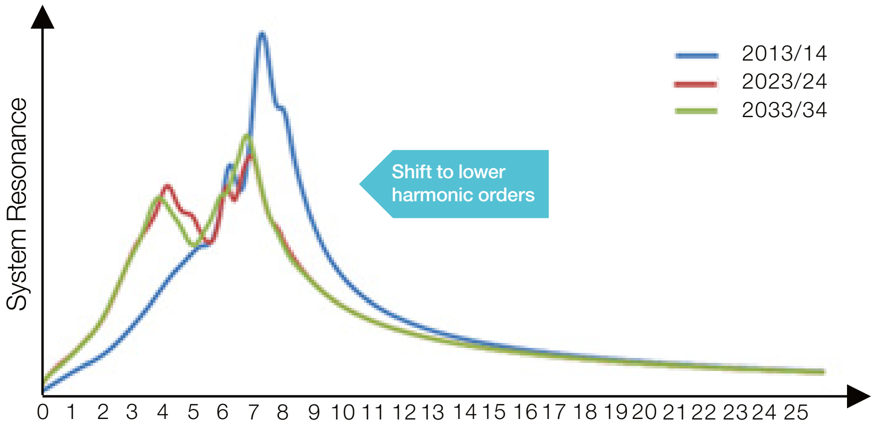
- Voltage magnitude
- Nominal frequency
- The shape of the voltage waveform (harmonic content).

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. In this section, Harmonics and Resonance as two of the key power quality issues which are affected by the changes in generation and demand background.

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, and converter connected generators and HVDCs also introduce harmonic content.

As SOF 2014 noted, the effect of a lower system strength is that there is a shift towards lower order harmonics (nearer 50Hz), causing an amplification of voltage distortion at lower harmonic orders. This occurs as a result of the distances between ideal sources of AC power on the system increasing such that the harmonics a 1/sqrt(LC) relationship shift down over time.

Figure 52
Illustration of Lower Order Harmonic Shift



Whilst intended as an illustrative example of the modal shift alone, it was notable in last year's analysis above that an additional modal resonance spike appeared in future year assessment and a reduction in voltage spike also occurred in future years. These two aspects of analysis lend themselves to more detailed inspection upon a full GB network model, which we have undertaken in our SOF 2015 assessments.

Power Quality

5.5.1 Impact on Operability

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. 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.

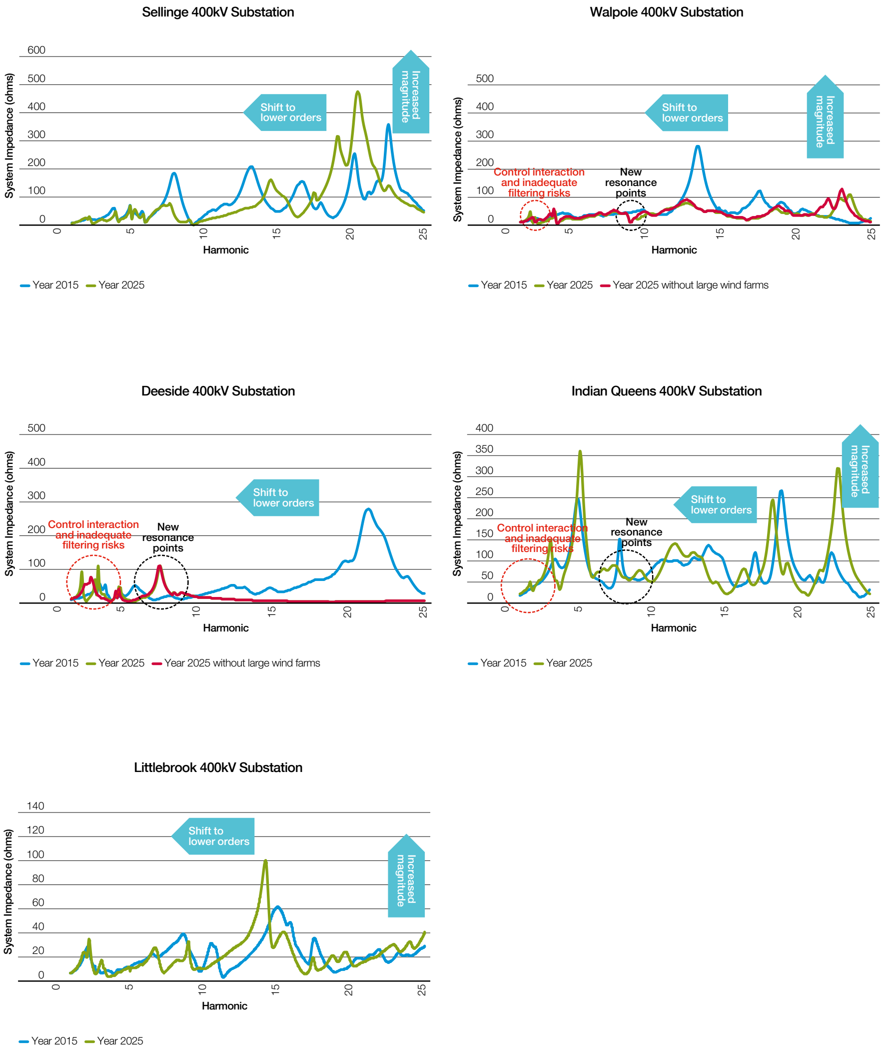
5.5.2 Assessments and Key Findings

To illustrate the impact of FES on change in resonance frequency, a series of frequency scans using full GB power system model were conducted for current year 2015 and the 2025 position. In all cases the base load flow reflects the minimum transmission system demand generation mix against a voltage profile within operational limits. The model used included detailed representations of the distribution system down to 11kV which have been supplemented with frequency dependent load models, reflecting the individual network resistive and inductive elements of the load relative to the supply voltage. The new generation connections have been constructed based upon supplied data, or generic parameter data where as yet limited data is available. Frequency sweeps have been conducted studying the system impedance changes up to 70th order.

The sites considered have been informed by TO experience of areas of current harmonic challenges:
- Littlebrook representing a highly meshed part of the network, with significant cabling;
- Indian Queens representing a remote note; connected radially to the rest of the system;
- Sellindge representing a node with large converter connected infeeds; and
- Walpole representing a connection hub for large offshore wind farms.

As can be seen in all results, shifts to lower orders of harmonic emission are complimented with a general increase in the scale of impedance spikes observed in those harmonic distortions in future years. 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; this is an area of exposure also to both customer and network owners as there is a possibility that existing filter solutions become ineffective against future range of emission background observed, or can be stressed by that background of emissions, and indeed that new filter solutions may be required in such future conditions.

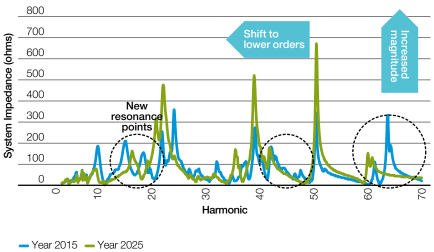
Figure 53
Frequency Scans up to 25th Harmonic Order in 2015 and 2025



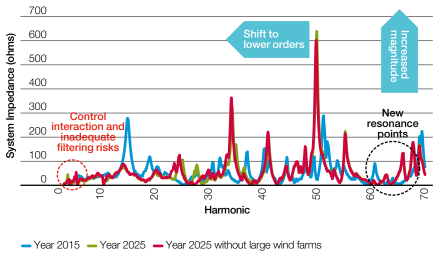
Power Quality

Figure 54
Frequency Scans up to 70th Harmonic Order in 2015 and 2025

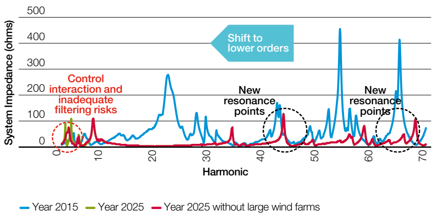
Sellinge 400kV Substation



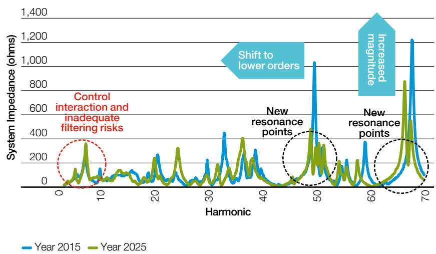
Walpole 400kV Substation



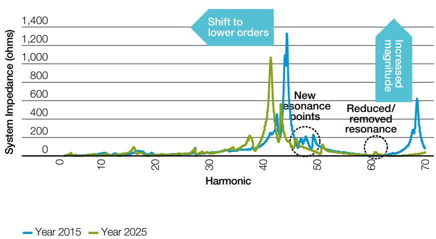
Deeside 400kV Substation



Indian Queens 400kV Substation



Littlebrook 400kV Substation



Chapter five

5.5.3
Work in Progress

The underlying assumptions made to evaluate long-term impact of FES on power quality are only appropriate so far as to illustrate the expected trend in changes in system resonance. Detailed 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. An update to this process G5/5 is underway which improves the ability to deal with increasingly complex and cumulative emissions in future years, and a further working group reviewing ER G5/4 is in operation within the Grid Code (GC0036)

In England and Wales base-lining work 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 number of permanent and portable monitors in 2015/16, providing extensive coverage for 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

We also understand that a number of DNOs are exploring the option of integral power quality monitoring being included in new switchgear specification to complement monitoring. Various monitoring devices are also being installed in Scotland on key areas of the network to enable the observance and measurement of system parameters; for example those intrinsic to the VISOR project.

Power Quality

5.5.4
Mitigating Options

In future years, to mitigate the potential impact of changes in system resonance, and future power quality challenges a range of new additional options can be explored.

- Dynamic Filters Using New Statcom/VSC Controllers:
  The new VSC type converters can intrinsically be configured to produce emission counter-correlated with certain harmonic frequencies on a flexible/ adaptive basis. Such solutions however reserve capacity that would otherwise be applied to active power or reactive power steady state capability. There is limited existing history of application which would mean such solutions would need to be further examined and where appropriate new code framework introduced surrounding implementation

- Synchronous Compensation:
  Synchronous compensation is an established technology which could and has historically been applied to the transmission system at modest scale (devices no larger than 150MW) ahead of the development of SVC and STATCOM type technology. In order however to address the impacts discussed above the scale of the increase in synchronous compensation would need to be far larger in order to have the desired effect of damping new harmonic orders, stabilising modal shift and increases in the magnitude of harmonic emission spikes observed. At such scale, the question of whether such devices would more appropriately have an active power generation capability as opposed to a loss characteristic can be raised, and as such whether across the industry new frameworks for such a service would need to be developed.

LCC HVDC Commutation Failure

5.6 Background

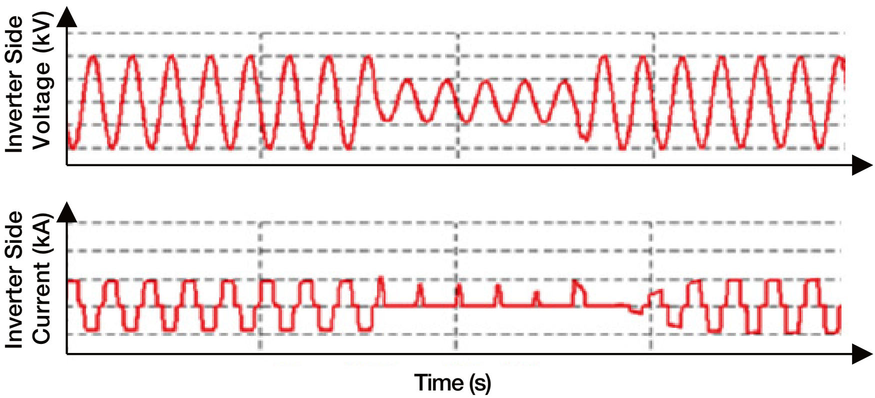
The interaction between the AC network and HVDC links is one of major concern in hybrid AC/DC power systems. The significance of the interaction between the AC and the DC systems depends on the strength (short circuit level) of the AC system at the HVDC converter bus.

Commutation failure happens if the commutation of current from one Line Commutated Current (LCC) based 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 LCC HVDC links.

Figure 55
Illustrative LCC Type HVDC Commutation Failure



LCC HVDC Commutation Failure

Only the HVDC links based on LCC 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.

Short circuit index alone is only one measure of short circuit strength- effective short circuit strength adds to the rating of the LCC Type HVDC convertor the non- flexible compensation scale to the convertor rating in the calculation of short circuit index noting its potentially destabilising action on AC power recovery.

5.6.1 Impact on Operability

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 ultimately be interruption of power transmission, or inability to operate the LCC based HVDC links in inverter mode at full transfer levels.

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 LCC based HVDC links to ensure the avoidance of commutation failure.

5.6.2 Assessment and Key findings

Studies have been carried out to estimate the fault levels at the converter stations of the current HVDC links and to evaluate possible mitigation actions. These review the April-October period of low demand potential against typical plant availability and penetration data over that period, a representative sequence of network access and duration and availability and interconnector operation against the forecast changes in demand and generation mix occurring over the period. Results are based on the effective Short circuit level context discussed above. An example of the impact upon the oldest of the installed LCC-type convertors is represented in Figure 56.

Figure 56
Load Duration Assessment of Sellindge 400kV System Strength Against SCL (2014 Assessment)

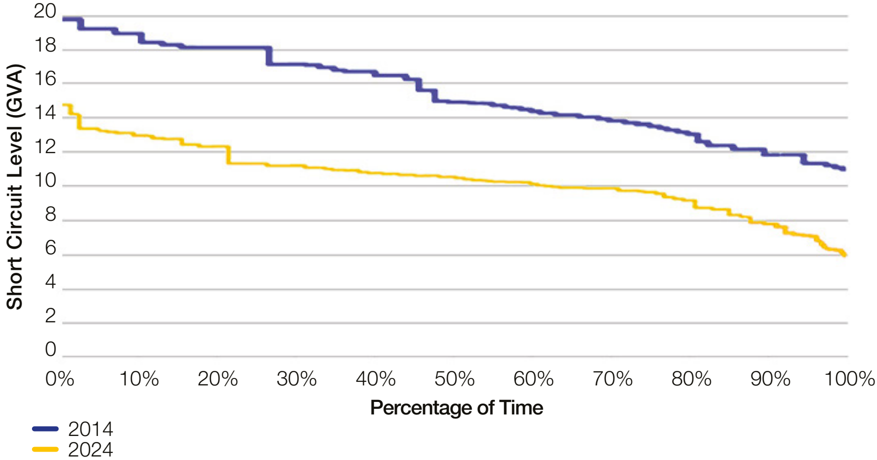
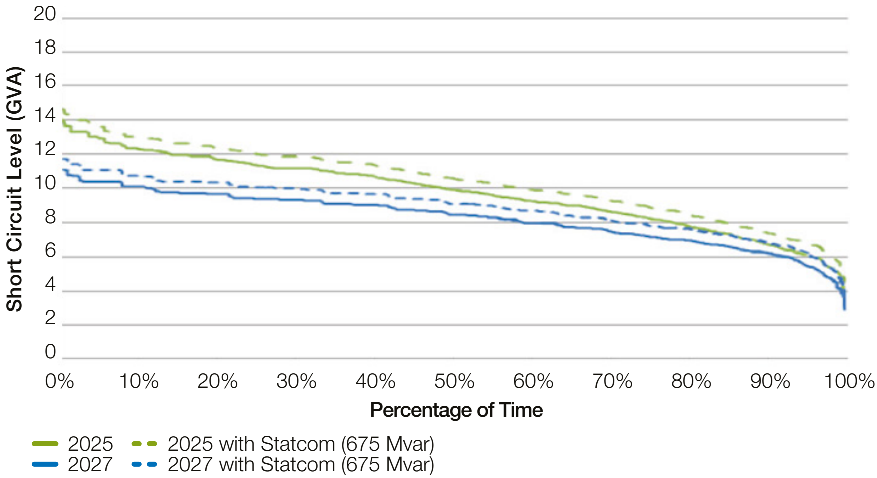


Figure 57
Load Duration Assessment of Sellindge 400kV System Strength against SCL and Effective SCL with STATCOM (2015 Assessment)



LCC HVDC Commutation Failure

As can be seen in the above comparison the load duration and scale of short circuit level have declined more compared to 2014 as a result of those factors discussed within the short circuit level section. The assessment for Sellindge further illustrates that new operational measures may be needed (such as outage coordination, fast acting voltage controller) to mitigate the reduction of SCL at the converter stations of LCC-HVDC links so the links can be satisfactory operated in inverter mode.

5.6.3 Work in progress

As mentioned earlier, at the design stage of HVDC links, the variations of SCL are taken into account. Based on the commutation failure risk assessment, we have currently developed a methodology for continuously monitoring the SCL at the converter stations and check against the performance of the HVDC links.

5.6.4 Mitigating Options

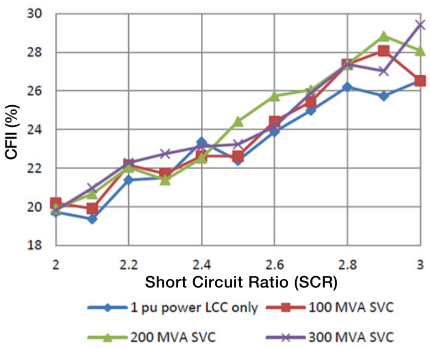
Reactive power compensation is widely used to improve voltage stability in the steady state and the transient state of power systems. Some possible means of voltage regulation are the Synchronous Condenser (SC), the SVC and a STATCOM.

SVCs and STATCOMs increases the ability to control the converter bus voltage. However, these devices are not rotating machines so they do not increase the short-circuit level at the converter bus bar. 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.

A further measure of Commutation Failure Immunity Index (CFII)[3] has been considered. This has considered the combinational effects of coincident VSC operation proximate to LCC type HVDC and compared this to the effect of SVC and STATCOM devices. This has concluded, as noted in figures below that whilst STATCOM can positively contribute to an improved CFII, with VSC this is not necessarily the case where both VSC and LCC type HVDC connections are both exporting or importing power simultaneously. Similarly CFII assessment notes that SVCs whilst providing useful post fault support services do not in general provide sufficient support during fault recovery to support commutation challenges.

[3] Comparison of Different Technologies for Improving Commutation Failure Immunity Index for LCC HVDC in Weak AC Systems. – Joe Burr PhD project sponsored by National Grid

Figure 58
Comparison of CFI with Short Circuit Ratio Noting Influence of Statcom and SVCs



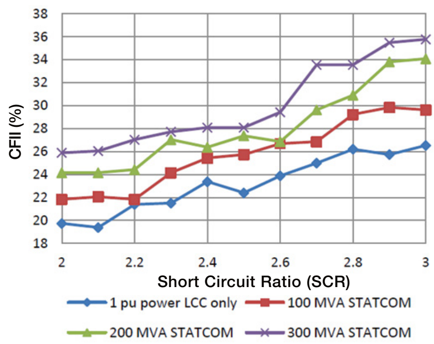
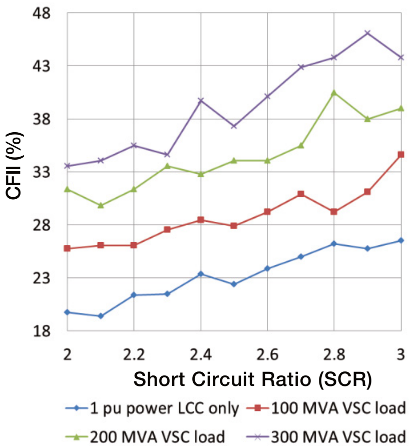
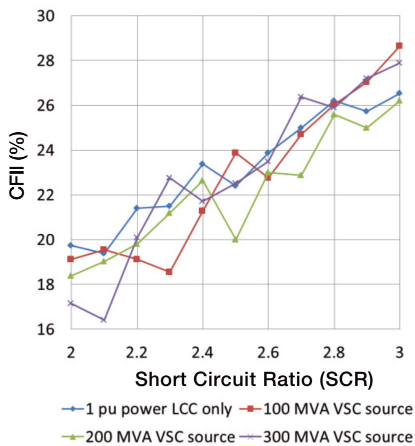


Figure 59
Comparison of CFI with Short Circuit Ratio Noting Influence of VSC as a Source or Load





Chapter five

Demand Control by Voltage Reduction

5.7
Background

National Grid ("NGET") discharges the role of System Operator within Great Britain, ensuring that system demand and generation are continuously in balance to maintain system availability and reliability. Demand control is one of the operational measures which allows SO to maintain the balance of generation and demand at times of system stress. This area of control is covered by the Grid Code Operational Code 6 (OC6).

The traditional approach under Grid Code OC6 has been to seek to reduce the voltage target at the Transmission/Distribution interface as a method of achieving reduced demand under emergency scenarios. The benefit of this technique is that, unlike demand shedding, no physical load is disconnected.

This approach is founded upon the voltage dependant behaviour of demand, coupled with the normal operational principle of the distribution system which is to define the cascaded voltage profile of the radial distribution system to the voltage targets assumed at the Transmission/ Distribution interface. The assumption has been that a voltage reduction of 5% at the Transmission/ Distribution interface delivers around 3% reduction in active power, but this assumption has been subject to limited practical test since privatisation.

5.7.1
Impact on Operability

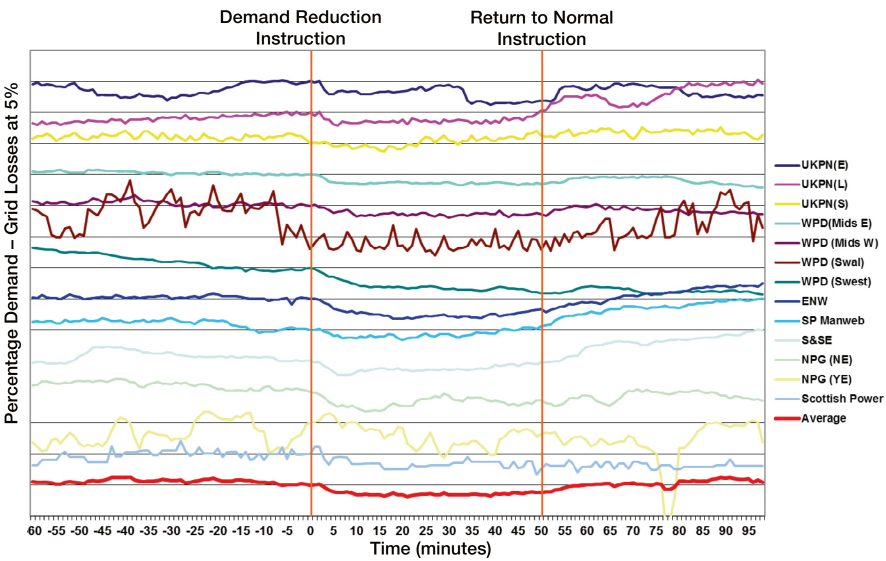
Given that the demand reduction by voltage control for SO is one of the operational measures that is rarely used (used as an emergency measure), it is important to understand that whether this measure in coming years is a viable option, or not. Under OC6 if insufficient demand reduction is available in these scenarios, a first stage of physical demand disconnection is then required which would impact customers directly in such scenarios. Whilst the impact would be minimised and prioritised by the distribution companies involved in that activity, it would clearly be preferable, where possible to avoid such consequences.

5.7.2
Assessment and Key findings

Under "Project Juniper" demand reduction tests were conducted in October 2013 and it concluded that a much lower average of 1.5% reduction was observed with much variance across distribution systems. There are many factors which could have affected such low level of demand reduction and are further investigated, including:

- Degree of voltage dependency of loads;
- Effectiveness of change of voltage set-point and cascaded effect in the distribution networks; and
- Cancelling out the effects of voltage reduction, by corrective actions in the distribution network.

Figure 60
Change in Load by DNO Area As Observed in Operation Juniper Demand Control by Voltage Reduction Trial



Demand Control by Voltage Reduction

5.7.3 Work in progress

National Grid initiated project DIVIDE (DNO investigations into Voltage Interaction and Demand Expectation) which seeks to gain an improved understanding and modelling capability of demand control. Its approach to this challenge is to first develop load models and load profiling reflecting anticipated behaviour building on the outcome of the Electricity North West CLASS project, and then to repeat Juniper trials at strategic times in the daily load curves and concentrating on the validation of those trials with modelling.

5.7.4 Mitigating Options

As discussed above based on the early nature of analysis, it would not be appropriate to assess mitigation in detail. Mitigation could come from a range of process or approach changes identified via the DIVIDE project.

System Emergency Restoration

5.8 Background

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, as a prudent System Operator, National Gris continuously assesses the system restoration measures and capabilities.

In a black start condition, the System Operator has a plan and a set of policies detailing the approach that would be taken towards restoration of the network. Restoration services are currently contracted from an array of thermal plants technically capable of re-energising the system. The guarantee that a structured approach to network restoration would be possible depends on the availability of these services.

Across the period of system 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 part of the network are restored and demand block loads are allocated; and
- The inertia, control and dynamics of the power island are dominated by the behaviour and the capabilities of the Black Start generator.

System Emergency Restoration

5.8.1 Impact on Operability

In SOF 2014 we had highlighted a number of potential evolving concerns associated with the Black Start service as the energy market background scenarios discussed within FES evolve over future years. In the SOF 2015, we have further assessed this system restoration topic, and from operability perspective, the following areas are covered:

5.8.1.1 Service Availability and Types

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.

5.8.1.2 Availability of Block Loads and Performance of Embedded Generation

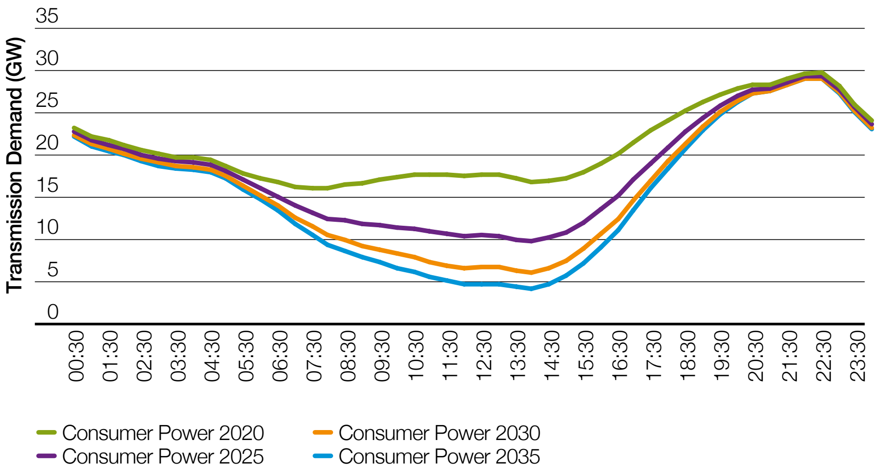
In addition to the Generation resources required to achieve Black Start, to achieve a viable approach, the generation is required to re-energise demand across network elements in a defined and manageable extent. Embedded generation also has a potential effect upon both the predictability of the "Block-Loads" within those network elements, and over how frequency is then regulated between black start generator and embedded generator following their restoration to any Block load. If the generator protections and control responses are not appropriately specified/ accounted for in the strategy, additional generation response characteristics and potential instabilities in the load/ generation "power islands" created under Black Start conditions. In this context it is clear that distribution protection and control philosophy will have the potential for substantially greater impact on Black start strategy going forward.

5.8.2
Assessment and Key findings

5.8.2.1 **Service availability and types**

Within Chapter 7 of FES 2015 we discuss the energy balancing challenges of the Consumer Power scenario as it appears in 2015, 2025 and 2035 for a typical summer day. Figure 61 below illustrates across the day the extent to which the availability of future levels of synchronous plant decline. This assessment has been assembled without additional operator action being otherwise applied within the Balancing Market to affect these trends.

Figure 61A
Summer Balancing Case Study With Proportions of Generation By Type (Chapter 7 FES 2015)



System Emergency Restoration

Figure 61B
Summer Balancing Case Study With Proportions of Generation By Type (Chapter 7 FES 2015)

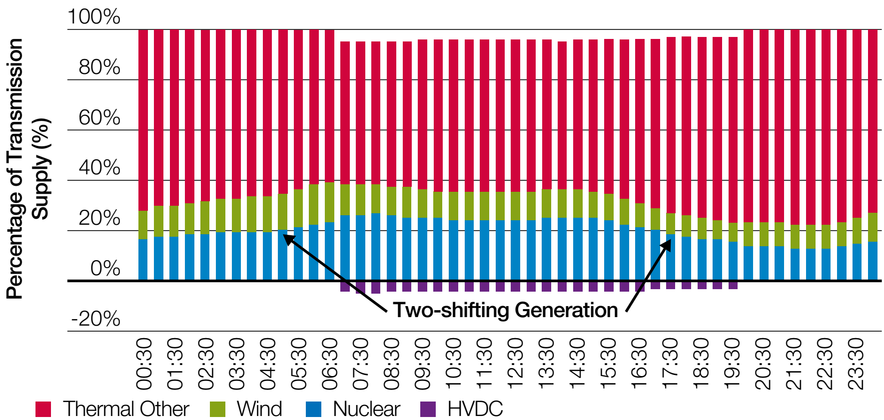


Figure 61C
Summer Balancing Case Study With Proportions of Generation By Type (Chapter 7 FES 2015)

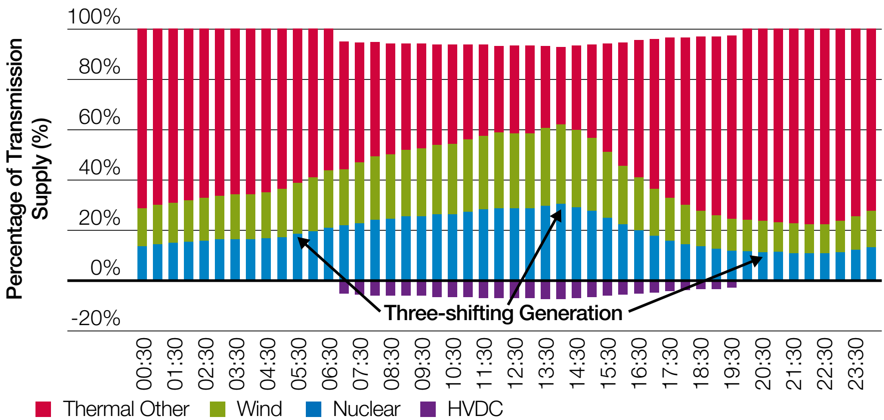
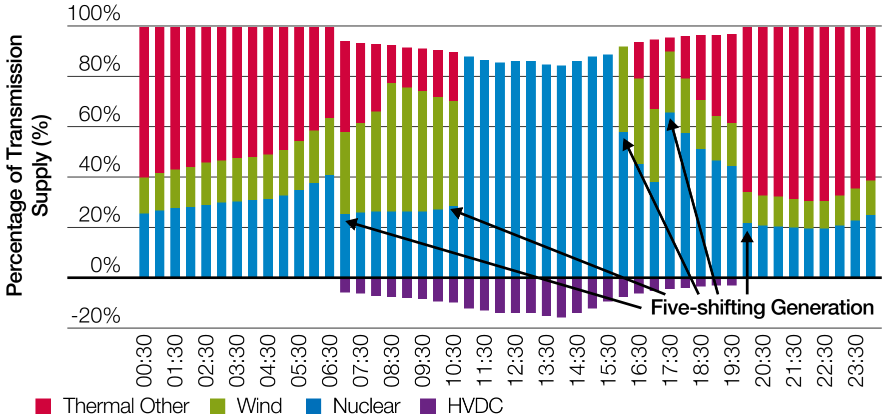


Figure 61D
Summer Balancing Case Study With Proportions of Generation By Type (Chapter 7 FES 2015)



Referring to figure 63, the reduction in available thermal plant in merit to meet transmission demand will in turn affect the black start service availability from thermal plants. Across the FES, the black start service availability is affected by the CP and GG scenarios most severely, with by 2027 onwards less than 2000MW of available traditional thermal plant expecting to be running during periods of minimum load.

Such low levels of thermal generation in merit will not be sufficient to provide black start service in order to meet current strategic approaches in diversity in volume and geography, but also there would be no guarantee that this level of thermal generation capacity to be capable of black start services. As such in the FES 2015 data, it is clear that over the next 15 years traditional thermal providers which have historically been the backbone of system restoration strategy would increasingly be unavailable for this purpose.

System Emergency Restoration

Figure 62
Minimum Demands by FES 2015 Scenario

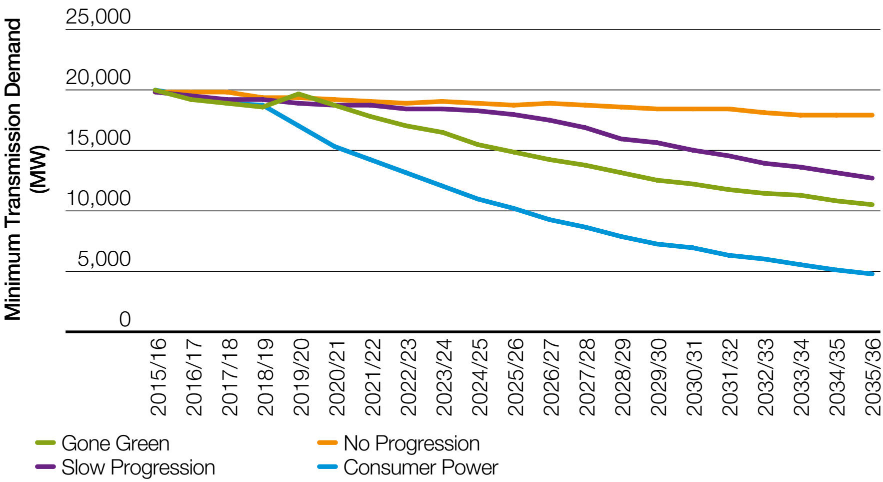
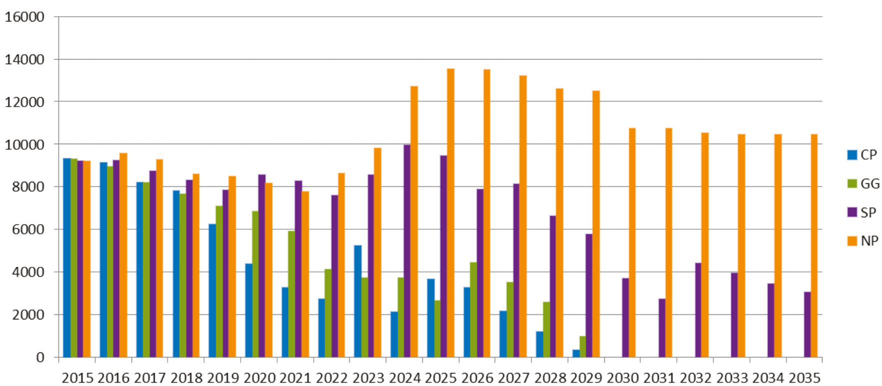


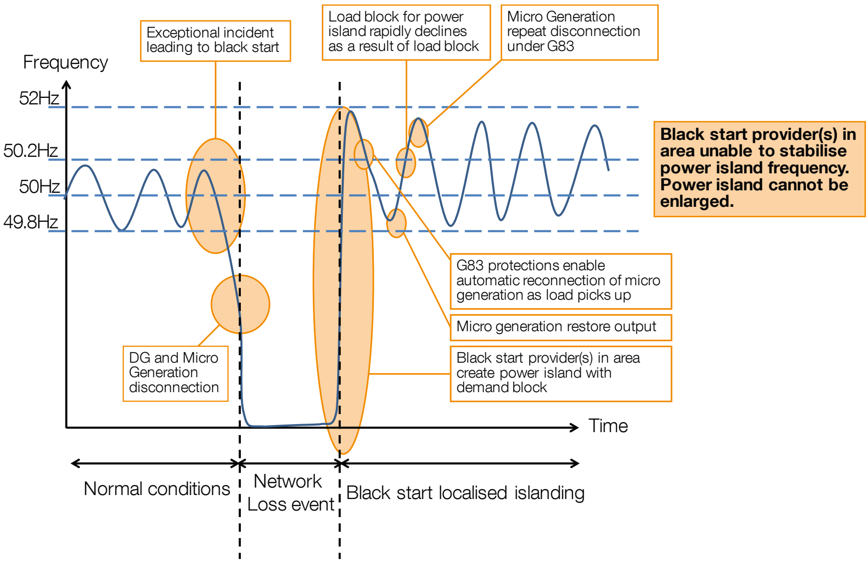
Figure 63
Transmission Connected Non-synchronous Generation Contribution at Mimimum (Excluding HVDC)



5.8.2.2 **Availability of block loads**

The restoration of the system after a black start condition involves energisation of the network, and restoring the energy supply to demand stage by stage; known as block loading the system. A key concern surrounds the effect that embedded generation has on the stability of block loads across demand blocks.

Figure 64
Stability Concern Surrounding Stability of Block Loads during Black Start Events



Currently all micro generation will be subject to ER G83 protections which operate on a basis that for frequency excursions beyond defined tolerances the generation will automatically disconnect, and automatically reconnect when the frequency recovers within the acceptable bandwidth. Distributed Generation above 1MW are connected similarly, or subject to DNO's requirement tend to be installed subject to ER G59 protections.

Following an exceptional incident an area may be disconnected/de-energised. As a result of the event the originally connected micro-generators in this area will be disconnected. During the restoration of a network due to low inertia level, the frequency of the system may be volatile. The black start generators are required to contain the frequency within a range between 47.5 and 52Hz. As frequency reduces to 51.5Hz the embedded generation covered

System Emergency Restoration

by G83 relays or automatic restoration via a G59 scheme will subsequently automatically connect and begin to increase output, and effect that once material a greater generation to demand disparity will rapidly then drive the power island frequency up beyond 51.5Hz once more, at which point, within 15 seconds the protections will once again disconnect. Once frequency is restored below 51.5Hz a further reconnection will occur followed by a further disconnection following a further over-frequency event.

The Black Start provider across this characteristic will be hunting to stabilise repeated over-frequency/ under-frequency disturbances which in the worst case would destabilise the generator forcing a re-start of that power island. Specific dynamic behaviour would depend upon the black start provider and the rates at which particular embedded generation subject to reconnection ramp and then disconnect across this characteristic. Without resolution this issue could potentially invalidate the basis of current black start approaches.

5.8.3 Work in progress

Transmission System Operators within ENTSO-e are driving the creation of an “Emergency and Restoration Code”, which seeks to standardise best practice process in the management of inter control area black start. 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 GB, 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.

National Grid has already initiated a detailed study; working with number of consultants and academics, into the potential for practical Black Start islanding services, expected to report early in the New Year. Further technical studies will be sought to consider the following areas:-

- Use of NSG, Energy Storage, and VSC-HVDC energise a de-energised network
- Introduction of revised protection approaches or control measures to avoid block load instability
- Case study of embedded generation Black Start strategy in conjunction with DNOs to inform the viability of a bottom up system restoration.

5.8.4
Mitigating Options

A number of new services can be developed in order to tackle the challenges mentioned in this section:

- Use of Non-Synchronous Generation for Block-Loading
  As discussed earlier in this section, the system frequency during the system restoration is highly volatile, and there is a risk that thermal generators in extreme condition cannot withstand such volatile frequency. The large converter connected generators and infeeds due to de-coupling nature of them, whilst still require AC grid voltage waveform to synchronise to, are less susceptible to variations of rate of change of frequency. This feature makes them ideal new sources for block-loading to minimise the full demand restoration time.

  Whilst this option has not been explored in the industry, the parameters and capabilities of new technologies, such as new wind farms and VSC HVDC links 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.
- Energy Storage
  Different energy storage technologies if in suitable state of charge prior to the black out, will have the ability to assist in both energisation, and block-loading the system
- DSO Services
  The existing system restoration strategy as mention earlier is a coordinated plan with generators and distribution network operators. In the future, if the ability to dynamically manage the distributed resources exist via a DSO, various options such as restoration of the full system via multiple DSOs from a much wider pool of resources will become viable.

Chapter 6 Embedded Generation

- Key Messages
- Regional System Stability
- Low Frequency Demand Disconnection
- Active Network Management (ANM)
- Demand Forecasting with High Levels of Embedded Generation

Key Messages

6.1
Key Messages

- As identified in Chapter 7 of FES 2015 (Summer Balancing Case Study), in 3 of the 4 FES scenarios (Gone Green, Slow Progression and Consumer Power) embedded generation determines new daily load shapes. There is a transition from early morning to early afternoon transmission minimum demand within the next 10 years driven by embedded generation under these scenarios.
- The existing and increasing amount of embedded generation at lower voltage levels increases the risk of disconnecting net generation if Low Frequency Demand Disconnection (LFDD) relays operate
- The majority of the stability challenges which relate to the increase in embedded generation arise from voltage instability due to large power flow exchanges between networks and a lack of sufficient dynamic voltage control capability.
- National Grid and Distribution Network Operators are currently working collaboratively in order to consider the whole-system impacts of increase in embedded generation (as part of the Embedded Generation Working Group). This close collaboration has proven to be successful and crucial in determination of system needs and considerations of the challenges identified as part of the SOF.
- With the increasing use of Active Network Management (ANM) on distribution networks and their greater complexity, closer interaction will be needed between distribution system control and transmission system operation.

Regional System Stability

6.2
Background

System stability is typically determined by a combination of two factors: system inertia and short circuit level, as discussed in earlier chapters. The system inertia during the initial period of a disturbance is a key factor in determining the response of the system. It is critical to have either enough inertia or sufficiently fast response 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, rotor angle oscillation or voltage stability challenges. Short circuit level is an indication of the amount of voltage support that can be provided to a specific point on the system. The magnitude of the short circuit level and available voltage support not only determines the voltage depression during a short-circuit fault, but also affects voltage stability and voltage restoration. This is known as post-fault voltage compliance. A low short circuit level might result in an instantaneous local voltage depression across a region during and after period of a disturbance or a fault, followed by slow voltage recovery.

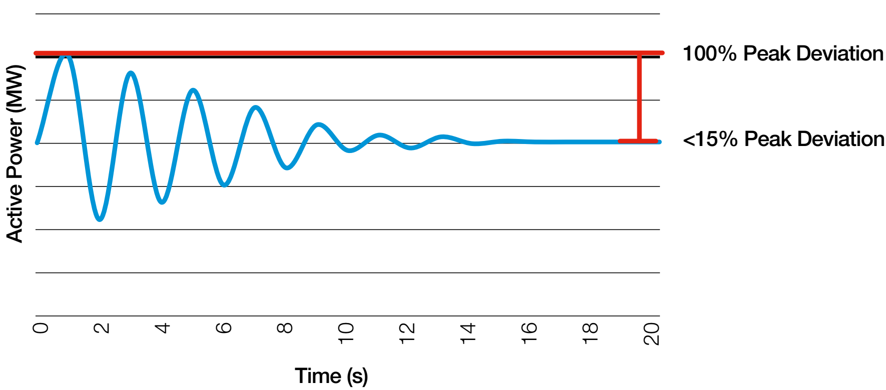
Due to the principles of the AC power system operation, conventional evaluation of system strength is based on synchronous generation which naturally provides support to the system by contributing to system inertia, voltage control, and high short circuit currents. Embedded Generators (EG), on the other hand, are connected to the distribution network and are not currently required to provide mandatory voltage control which is a Grid Code requirement for large generators. Furthermore, some embedded generators are Non-Synchronous Generation (NSG) which is de-coupled from the system via converter based connections as discussed in Chapter 4, System Inertia. This type of connection prevents NSG from contributing to system inertia and short circuit level in the same way as a synchronous machine (due to the characteristics of the converter) and which therefore has the potential to expose the system to more stability related challenges.

Regional System Stability

6.2.1
Impact on Operability

System stability is not achieved exclusively from the rapid provision of power based on the system frequency. Stability also requires that sufficient dynamic reactive power reserves are dispatched to stabilise and recover the voltage regionally. According to FES 2015, under some scenarios the installed capacity of EG increases drastically in future years which has the effect of displacing transmission connected generation at periods of low demand. There is a challenge in establishing visibility and control of embedded generation for the System Operator (SO) which is currently very limited and visible only from the offset effect on transmission system demand. This makes real-time operation of the system significantly more challenging as we need to ensure the system is secured against various contingencies based on a less visible generation background. Therefore, we have conducted the studies presented in this chapter to better understand the impact of increase in embedded generation on system stability for different regions. Due to variations in geographical generation mix and network impedance, different regions of the GB power system have inherently different capabilities within required limits. Figure 65 indicates the power oscillation damping requirement as specified in the Security and Quality of Supply Standard (SQSS).

Figure 65
NETS SQSS Power Oscillation Damping Requirement



6.2.2
Assessments and Key Findings

Four regions in GB have been presented in the assessments below on the basis of large volumes of EG which are either already connected or anticipated to connect in these regions, or network specifics: total impedance and number of circuits connecting the regions and the rest of the system. These regions are Scotland, South West, South East and North Wales. Figure 66 shows where each area is geographically located in GB.

Transient stability assessments have been undertaken for each of these areas against the Future Energy Scenarios (FES) backgrounds.

The assessment results have indicated that the majority of the stability challenges are attributable to voltage instability due to the lack of sufficient dynamic voltage control capability. To illustrate this effect better, Figure 67 shows three different states of the system; mode A showing the network in the South West of England with sufficient level of reactive compensation to maintain the voltage stability, mode B showing the system with moderate level of embedded generation, and mode C shows the system response with even more volume of embedded generation and insufficient voltage control capability which shows an unstable mode.

Regional System Stability

Figure 66
Regions in the Assessment

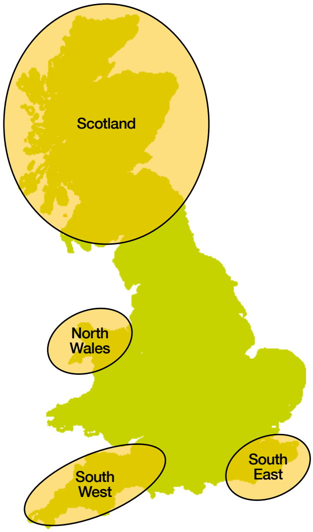
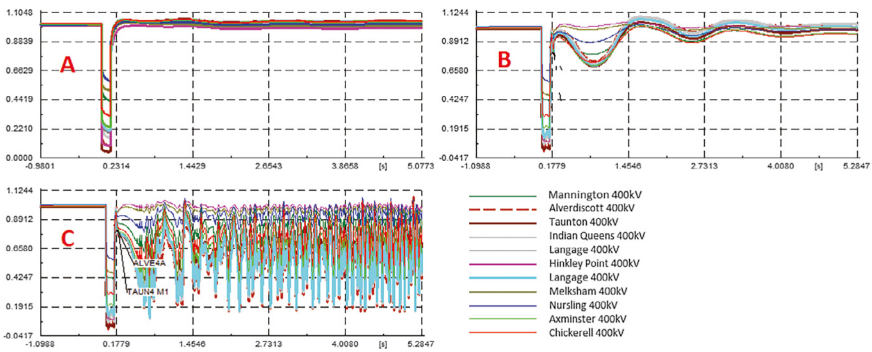


Figure 67
Changing System Response Dependent on Level of Embedded Generation



In different regions, different mitigating actions have been suggested to accommodate the power infeed from EG according the assessment results. The summary of main challenges identified in the assessments is tabulated in Table 3.

Chapter six

Table 3
Potential Stability Challenges Identified in Studied Regions

Region	Network Details	NSG Running Capacity[4] to Trigger Potential Stability Challenges	Potential Stability Challenges
South West	■ Network topology: two 400kV transmission double circuits connecting this region with the rest of the transmission system ■ Main synchronous power plant: thermal power station (CCGT) ■ Main NSG Source: embedded Solar PV generation.	2.5GW	Voltage instability: post-fault voltage instability combined with Temporary-over-Voltage(ToV)
South East	■ Network topology: two 400kV transmission double circuits connecting this region with the rest of the transmission system ■ Main synchronous generation: nuclear power plant, and embedded thermal unit ■ Main NSG Source: HVDC Interconnector, Embedded Solar PV.	3.2GW	Voltage instability: post-fault voltage instability combined with Temporary-over-Voltage(ToV)
North Wales	■ Network topology: two 400kV transmission double circuits connecting this region with the rest of the transmission system ■ Main SG: thermal generation and pump storage ■ Main NSG Source: transmission connected wind generation.	No significant stability challenges have been identified in current study.	No significant stability challenges have been identified in current study.
Scotland	■ Network topology: two transmission double circuit routes connecting this region with the rest of the transmission system in England and Wales ■ Main synchronous generation: combination of thermal, nuclear and hydro power plants ■ Main NSG Source: transmission and Embedded wind generation.	3.5GW	Voltage instability combined with rotor angle oscillation: post-fault voltage instability combined with Inter Area Oscillation and High Rate of Change of Frequency in Scotland (RoCoF).

[4] It is worth noting that NSG running capacity refers to the actual output of NSG, which is normally less than NSG installed capacity.

Regional System Stability

6.2.3
Mitigating Options

Most of the limitations associated with the capability to accommodate additional EG capacity are due to insufficient dynamic voltage support. The mitigation options should therefore look to enhance voltage control capability from a range of approaches:

- Sourcing voltage support from both transmission and distribution connected generation
- Additional transmission connected fast static/dynamic reactive compensation
- Constrain the active power output of connected non-synchronous generation in corresponding region below the maximum level of potential system instability issues
- Additional Power System Stabilizers (PSS).

Table 4
Potential Mitigating Options for Stability Challenges

Region	Short-Term Mitigating Options	Long-Term Mitigating Options
South West	■ Procure/install additional voltage support to prevent post-fault voltage instability on the system ■ Constrain off generation at critical times of the day (or put inter-tripping schemes acting post-fault) in such a way that the total post-fault power transfer does not exceed the identified limit in the region.	Enhance voltage support capability: ■ Working with DNOs to access the voltage control capability from the new and existing embedded generation ■ Operating the synchronous plants at low load, or as synchronous compensator for voltage support ■ Additional transmission/distribution connected dynamic reactive compensation (e.g. STATCOM).
South East	■ Procure/install additional voltage support to prevent post-fault voltage instability on the system ■ Constrain off generation at critical times of the day (or put inter-tripping schemes acting post-fault) in such a way that the total post-fault power transfer does not exceed the identified limit in the region.	
North Wales	■ No significant stability challenges have been identified, hence no mitigating options are proposed.	
Scotland	■ Procure/install additional voltage support near the Scottish boundary (B6[5]) to prevent post-fault voltage instability on the system ■ Constrain off generation at critical times of the day (or put inter-tripping schemes acting post-fault) in such a way that the total post-fault power transfer does not exceed the identified limit in the region ■ Investigate further improvements to stability through the use of the Western HVDC link and Series Compensation between the Scottish and English transmission networks. ■ Contract services delivering voltage support and system inertia on the Scottish network.	■ Enhance voltage support capability as above ■ Maintain sufficient level of inertia. Some the solutions may include Synchronous Compensator or conventional plans operating at reduced power output level ■ Improve Power Oscillation Damping (POD) capability on the Scottish system.

[5] National Grid website. Electricity Ten Year Statement [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

Low Frequency Demand Disconnection

6.3
Background

National Grid is obligated to maintain the system frequency between 49.8 and 50.2Hz under normal operating conditions. Under exceptional circumstances, for example loss of a large generator, the frequency should deviate outside the range 49.5 to 50.5Hz for no more than 60 seconds[6]. To achieve this, the SO contracts frequency response at any given time to be available in case an infeed on the system is unexpectedly disconnected.

In some rare cases a large generator loss that would be secured for, may quickly be followed by a subsequent loss of other generators, due to generator rotor angle instability for example, or cascading loss of embedded generation. For this extreme case, the secured frequency response holding may not be sufficient to maintain the system frequency between the statutory limits where the total generation loss exceeds the amount that is secured for, and a generation deficit may arise. In this circumstance the DNO low frequency relays may need to operate and disconnect demand customers in order to reduce the generation deficit (or demand excess) and maintain overall system stability. This procedure is called Low Frequency Demand Disconnection (LFDD) and is described by the Grid Code Operating Code 6 Demand Control.[7]

The last time a significant amount of customers were disconnected due to the operation of LFDD was 27 May 2008. The report outlining the events on the day is publically available[8]. The LFDD procedure was activated by the disconnection of two generation units within two minutes totalling 1582MW (the infrequent infeed loss limit at this time was 1320MW). Some of the back-up generation contracted for the day had already been used earlier following an earlier loss of generation. The near-instantaneous loss of 1582MW was then followed by a further loss that could be attributed to around 250MW of embedded generation loss. Although frequency response worked as expected for each of the individual losses, the combined magnitude of loss in such a rapid succession meant that the frequency reached 48.795Hz following the loss of the 250MW of embedded generation. Automatic LFDD was activated at 48.8Hz and this, with the support of fast-responding generation units, arrested a further fall in the frequency. For this particular event around 580MW of GB demand was disconnected by the LFDD scheme.

The investigation into this event initiated changes to the Grid Code Operating Code to clarify the total scheme operating time and the size of demand blocks to be disconnected within each stage, and to improve the consistency of the data submitted to National Grid.[9]

[6] National Grid website. NETS Security and Quality of Supply Standard [Online]. Available: http://www2.nationalgrid.com/uk/industry-information/electricity-codes/sqss/the-sqss/

[7] National Grid website. The Grid Code [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/

[8] National Grid, "Initial Report into System Events of 27th May 2008", June 2008

[9] Ofgem website. Grid Code [Grid Code D/09]: Grid Code Requirements for OC6.6 (Automatic LFDD) [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/62306/d09-d.pdf

Low Frequency Demand Disconnection

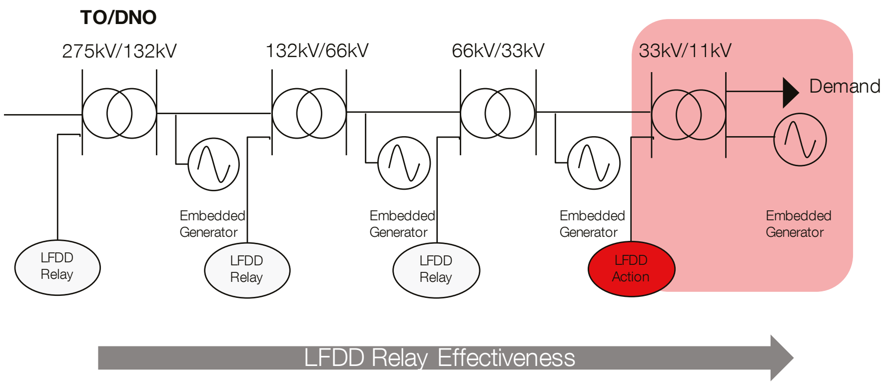
6.3.1 Impact on Operability

The growth in embedded generation in the recent years has been changing the way the demand is seen at the DNO/TO interface (Grid Supply Points), especially in the summer months when power consumption is lower and embedded generation output is higher. The load blocks that should be disconnected during LFDD operation are calculated based on the annual peak demand in each DNO area, which is not a representative condition for much of the year and can be considered the "best case" in the context of LFDD schemes operating as intended. This is because in many areas in the near future there may be enough embedded generation to meet the demand over summer and even export power onto the grid. This would make the particular areas with high concentration of embedded generation net generators from the System Operator (SO) perspective. The existing LFDD relays are not able to distinguish if the area they are meant to disconnect at a certain frequency threshold is a net producer or absorber of active power and would disconnect it regardless of the power flow level and direction. This means that for any disconnection of demand side customers, a large proportion of embedded generation, and possibly DSR units, may be disconnected, thereby depleting the potential frequency response resource in a situation when it is most needed.

6.3.2 Assessments and Key Findings

The effectiveness of LFDD schemes in disconnecting actual demand therefore should increase if the relays are connected at lower voltage levels, closer to the demand. The SO however, has little visibility of where and at what voltage levels the relays are connected.

Figure 68
LFDD Preferred Operation Point



A previous National Grid study into LFDD scheme design found that LFDD may be less effective in areas with extensive cable networks. As load is disconnected by the LFDD relays, the voltage in the area would rapidly increase. The local generating units may suddenly have to absorb large amounts of reactive power to reduce the voltage. If this absorption is very high compared to the steady state operating conditions of the machines, this, combined with high active power output in response to the frequency event, may cause the machine to lose stability and trip due to overvoltage protection. Another aspect of networks with a high proportion of cabling is that as the voltage across the network rises following demand disconnection, the effective demand also raises, making the scheme less effective.

To illustrate the challenge, Figure 69[10] shows the types and amount of generation connected at the distribution level (excluding micro generation, such as domestic PV). According to this, there is currently nearly 8GW of installed generation capacity connected at 11kV or below, therefore applying LFDD on lower voltage levels improves the scheme effectiveness, but it cannot completely disaggregate real demand from embedded generation at 11kV and below.

[10] This information has been obtained from the DNO Long Term Development Statements as part of an innovation project on Demand Response through Voltage Reduction.

Low Frequency Demand Disconnection

Figure 69
Embedded Generation Total Capacities and Location in GB

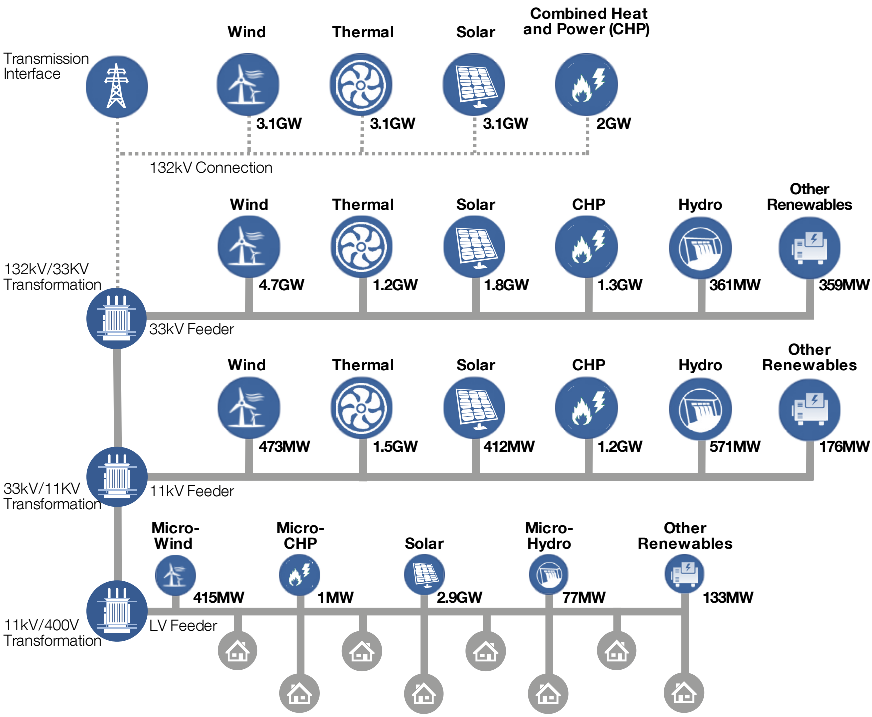


Figure 70 and Figure 71 show the areas where the distribution network is expected to be absorbing power from the transmission network, marginal areas and areas that are expected to be exporting power onto the transmission network by 2020/21 under each of National Grid's Future Energy Scenarios. This gives a view of which areas are more likely to experience the risk with respect to the illustration in Figure 69[11]

[11] This data was obtained from the models used for determining which GSPs are or will be exporting power onto the transmission system as part of the embedded (distributed) generation benefit review. Further information can be found on National Grid's website http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

Figure 70
GSP Average Expected Active Power Import/Export Across the Year

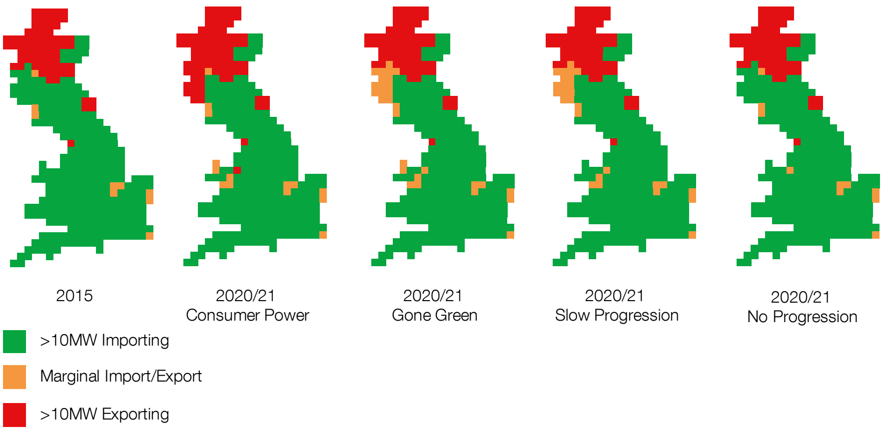
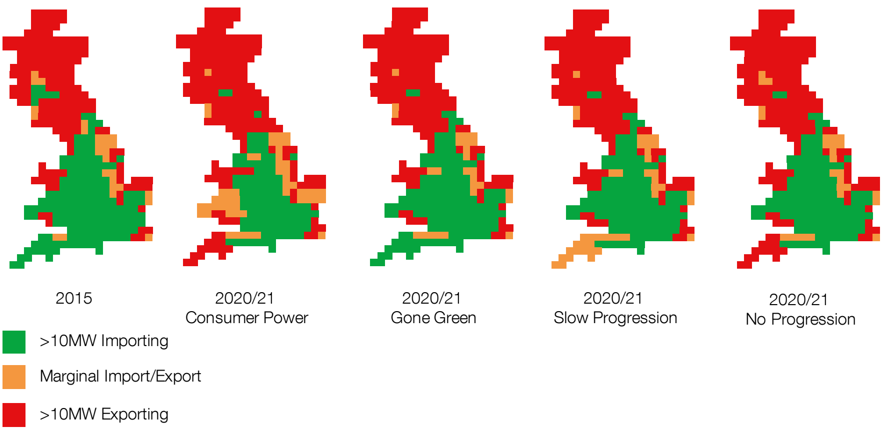


Figure 71
GSPs Expected to Be Exporting Active Power at Some Point During the Year



These figures provide the best view of areas where LFDD may be ineffective due to high amounts of embedded generation.

Relays in the areas marked red may disconnect net generation and make a low frequency condition worse.

Low Frequency Demand Disconnection

6.3.3
Mitigating Options

We have identified several possible routes to explore for mitigating the risk outlined above. These include:

- Refining the existing approach by understanding where exactly the relays are located, updating their settings to account for EG output and increasing RoCoF – the drop in frequency will be much faster in future and current settings may not be adequate
- Improving the existing approach using Active Network Management (ANM) like capabilities that would allow determining the power flow direction in real-time and prioritising relay operation to only disconnect net demand
- Disconnecting importing GSPs instead of relying on traditional LFDD which would give the SO confidence that what is being disconnected is net demand
- Engage with DNOs to ensure that LFDD scheme is effective and will disconnect the expected levels of demand throughout the year.

As a way forward, we will explore the practicality and impact of these options via bilateral engagement with the individual DNOs and report the progress in the SOF 2016 report.

Active Network Management (ANM)

6.4 Background

During past few years transmission and distribution network owners have received large amounts of applications from new generator customers wanting to connect to the network. A large proportion of these generators have been connected at the distribution voltage levels. Both remote areas and urban areas have seen a rapid growth in generation connections in the past decade, therefore the remaining available network capacity in certain areas can be limited. For the customers, this means expensive connections and long waiting times for the networks to be reinforced to allow full or partial export from the new generators.

On the transmission network this has been managed by the Connect and Manage[12] regime which allows the generators to connect to the system as soon as the enabling works (minimum work required to physically connect the generation to the network) are finished, before the wider network reinforcements are complete.

The DNOs have recently been adopting a similar approach with Active Network Management (ANM). The driver for this from a DNO point of view is the ability to defer reinforcements and outperform on the cost and time it would require to connect new customers in the traditional way. ANM schemes are providing a substantial economic benefit to the customers and the network owners and are central to the network planning strategies during the current regulatory period.

ANM schemes consists of monitoring and control systems that allow the detection of how much spare capacity is available on the local network at a given time and dispatching or constraining generation to ensure optimal use of the available capacity with no pre-fault thermal overloads. The generators can be typically constrained on a "last-in-first-out" basis, i.e. the last generator to connect to the network would be the first one to be constrained, or on a pro rata basis where all generators are constrained by the same amount. These and other considerations are described in the Electricity Networks Association (ENA) Active Network Management Good Practice Guide[13] published in July 2015.

The current examples of ANM projects include:

- Orkney Smart Grid[14]
- Northern Isles New Energy Solutions[15] (NINES)
- Capacity to Customers[16]
- Accelerating Renewable Connections[17]
- Flexible Plug and Play[18]
- Lincolnshire Low Carbon Hub[19]
- Western Power Distribution Alternative Connections (Business as Usual)[20].

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12 National Grid. Connect and Manage[Online].
Available: http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/connect-and-manage/

13 Energy Networks Association. Active Network Management Good Practice Guide [Online].
Available: http://www.energynetworks.org/modx/assets/files/news/publications/1500205_ENA_ANM_report_AW_online.pdf

14 Scottish and Southern Energy Power Distribution. Orkney ANM – Live [Online]. Available: http://anm.ssepd.co.uk/

15 Scottish and Southern Energy Power Distribution. Northern Isles New Energy Solutions (NINES) [Online].
Available: http://www.ninessmartgrid.co.uk/

16 Electricity North West. Capacity to Customers [Online]. Available: http://www.enwl.co.uk/c2c

17 Scottish Power Energy Networks. Accelerating Renewable Connections [Online].
Available: http://www.spenergynetworks.co.uk/pages/arc_accelerating_renewable_connections.asp

18 UK Power Networks website. Flexible Plug and Play [Online].
Available: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-%28FPP%29/

19 Western Power Distribution website. The Low Carbon Hub [Online].
Available: http://www.westernpowerinnovation.co.uk/Projects/Low-Carbon-Hub.aspx

20 Western Power Distribution website. Alternative Connections [Online].
Available: https://www.westernpower.co.uk/Connections/Generation/Alternative-Connections.aspx

Active Network Management (ANM)

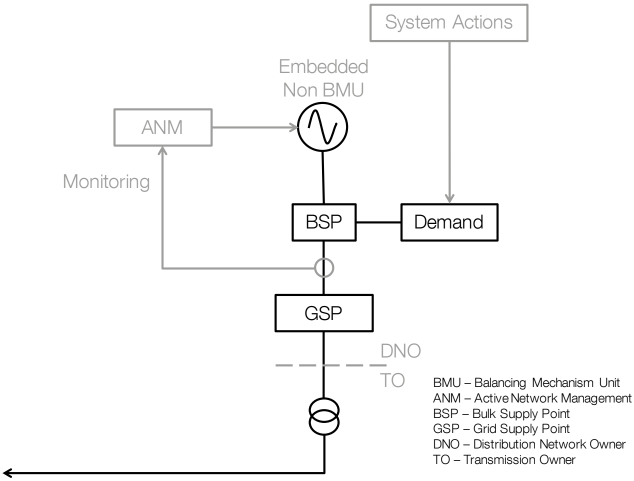
6.4.1
Impact on Operability

Without sufficient coordination between the SO, transmission, and distribution companies, the immediate impact of ANM schemes on the overall system operation is the increased uncertainty for short-term demand forecasting and interactions between System Operator (SO) and ANM actions. In the longer-term, as explained in the System Inertia section, it may be expected that a large proportion of the fast frequency response requirement will be provided by the distributed service providers embedded within the DNO networks, therefore the interaction between these and the ANM schemes that may be active in the same area will need to be understood and defined. Overall, ANM is a first step toward the evolution of Distribution System Operators (DSO). Provided that concerns noted in relation to the architecture options are addressed, ANM should not be detrimental to system operability.

6.4.2
Assessments and Key Findings

Most of these existing schemes have been put in place due to thermal or voltage network constraints on the DNO networks and the architecture follows the principles shown in Figure 72 and Figure 73.

Figure 72
Type-A ANM Architecture

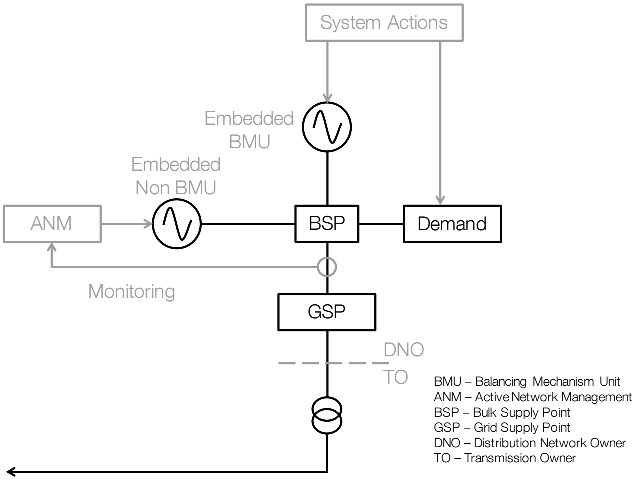


In the case of Type A (Figure 72), the SO can take actions for demand management (for example, Demand Side Response), but does not have direct control and visibility of the embedded non Balancing Mechanism Unit (BMU) generator that is only controlled and monitored by the ANM scheme (the ANM scheme is set up and operated by the regional DNO).

From the SO side this makes demand forecasting more difficult as the SO would not be able to tell if fluctuations in the GSP demand are due to changes in demand or output from the ANM unit. In the case where the demand customer may be providing Demand Side Response (DSR), the ANM unit may unnecessarily adjust its output and counteract the response from the demand customer.

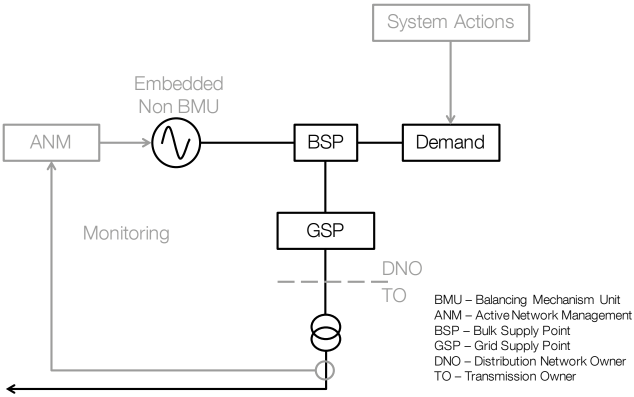
Active Network Management (ANM)

Figure 73
Type-B ANM Architecture



In the case of Type B architecture shown in Figure 73 above, the SO can instruct the demand and the embedded BMU generator that are connected to the distribution network, but has no visibility and control of the embedded non-BMU generator which is controlled by the ANM scheme. If, for example, the BMU was providing a Short Term Operating Reserve service to the SO, the ANM might see the subsequent change in spare capacity on the local distribution network and may instruct the embedded non-BMU to change its output accordingly, thereby counteracting the SO action. Depending on the size of each of the generators, this might make system balancing less effective. Such situations can be avoided by allowing the ANM scheme to receive information of the relevant SO actions (system actions) taken in its area and ensuring the ANM actions are taken accordingly.

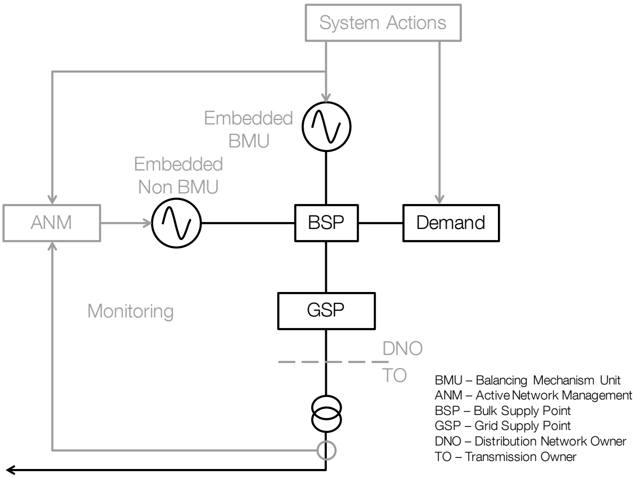
Figure 74
Type-C ANM Architecture



Whilst Type A and B ANM schemes are concerned with distribution network constraints, Types C and D, (Figure 74 and Figure 75 respectively), could alleviate constraints on the transmission network. Type A and C are similar in principle – the SO can only directly control the demand under certain circumstances; the ANM monitors the available capacity on the transmission network in its area and controls the output of the embedded non BMU generator accordingly.

Active Network Management (ANM)

Figure 75
Type-D ANM Architecture



In the case of Type D ANM (Figure 75), if the SO was to take an action on the demand unit to manage the local transmission network constraints, the ANM scheme may see this as a natural change in the network loading and send an instruction to the embedded non BMU generator to increase its output. Similarly to the Type B case, this would counteract the action taken by the SO and could lead to thermal overloads on the transmission network, therefore the ANM needs to receive information of the relevant actions being taken by the SO. More complex types of architecture would require significant interaction with the SO systems and would have to be evaluated and designed on a case-by-case basis as hierarchical control becomes increasingly challenging and complex.

6.4.3
Mitigating Options

Many of the existing schemes have been funded as innovation projects via Ofgem innovation funding mechanisms, and as such they have adopted different approaches and have been implemented in different areas. Going forward, best practice and experience gained through these innovation projects will be shared amongst the DNOs, TOs and SO through the ENA ANM working group to realise the biggest technical and economic efficiencies.

In the future, the ANM schemes could evolve to manage a much broader spectrum of system constraints, such as:

- Voltage and reactive power
- Short circuit current
- Pre-fault and post-fault thermal overloads.

Some of these principles are already being trialled on individual schemes, such as Capacity to Customers project in the Electricity North West area (post-fault management), RESPOND[21] project also in the Electricity North West area (short circuit current management) and voltage management in the Western Power Distribution area.

These new roles for ANM would require much more real-time interaction and visibility between the individual schemes or DNO control room and the SO control room, but they would also bring a lot of value to the SO based on the future operability requirements set out in this document, therefore the facilitation of this interaction as soon as possible is key to the evolution of ANM schemes.

[21] Electricity North West website. Respond [Online]. Available: www.enwl.co.uk/respond

Demand Forecasting with High Levels of Embedded Generation

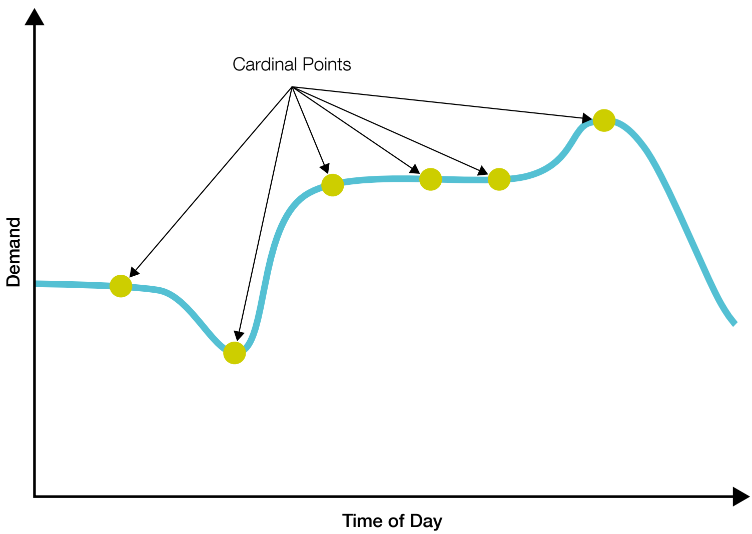
6.5 Background

One of the main task of National Grid as the system operator is to balance the real-time electricity demand and supply. To do this effectively and economically, the control engineers need to know what the system demand is expected to be several hours ahead of real-time to be able to schedule the necessary generation on the system. This is the demand as seen by the SO at the transmission/distribution interface (Grid Supply Point (GSP)), or the net demand:

Net Demand = Real Demand – Embedded Generation Output

Normally, the demand is forecasted nationally and broken down to each GSP accordingly. In addition, the demand is forecast day-ahead for specific points of interest, such as morning pick-up or darkness peak; these are called "cardinal points". A typical depiction of daily cardinal points is shown in Figure 76 below. During the day, the forecast is continuously adjusted based on the level of demand actually seen on the system in the previous hour.

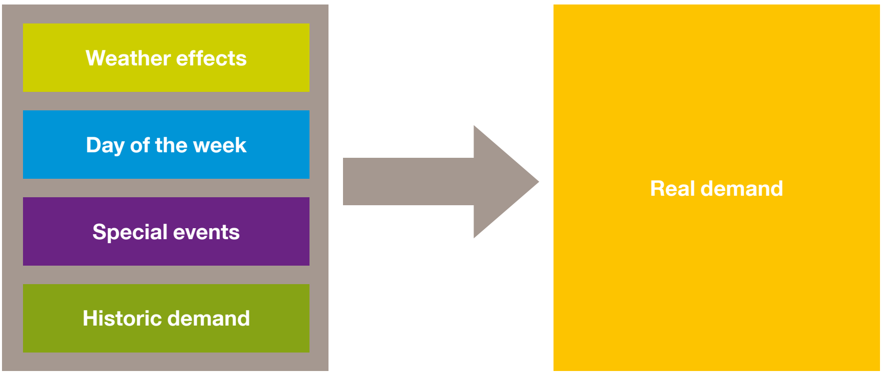
Figure 76
Cardinal Points



Real demand forecasts are based on 3 to 4 years of historic demand data and adjusted to take account of 25 factors, for instance:

- Weather (temperature, brightness, precipitation)
- What day of the week it is/holidays
- Special events e.g. popular TV programmes.

Figure 77
Real Demand Weather Forecasting

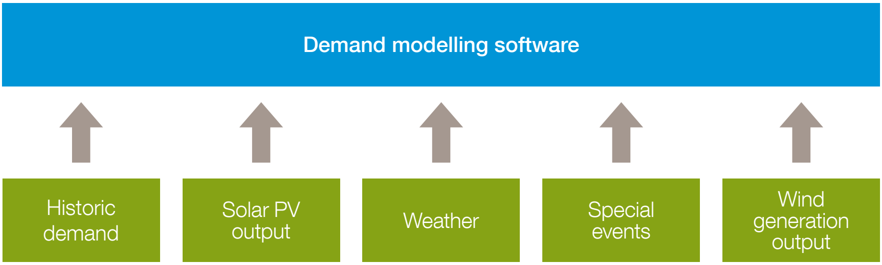


To estimate the output from embedded wind generators, the demand modelling software uses typical power vs. wind speed models for the most common types of generators in conjunction with Met Office data on wind speed and direction (66 weather readings across GB). The forecast results are adjusted based on the actual demand levels throughout the day.

Similar methodology is employed to forecast the output of the embedded solar PV generators. Since the pick-up of this technology has been more recent, there is less information available to build accurate forecasts. National Grid does not receive any metering data directly from the embedded solar PV generators, therefore generic power curve models (power vs. illumination) based on historic output data are used. There is ongoing collaboration with the Met Office to improve the solar irradiation forecasting for the 28 locations across the GB that the readings are currently available for.

Demand Forecasting with High Levels of Embedded Generation

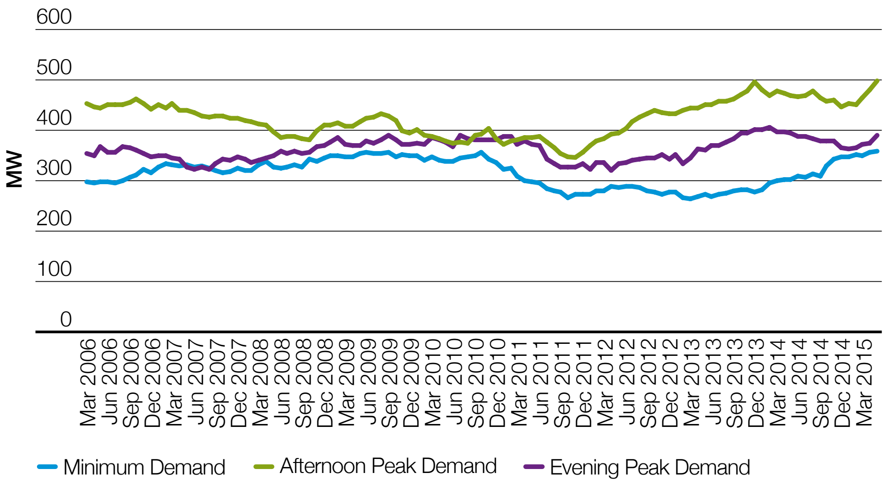
Figure 78
Transmission Demand Forecasting



6.5.1
Assessments and Key Findings

With over 15 GW of embedded wind and solar generation already connected, the difficulty in forecasting solar irradiation causes substantial uncertainty in real-time operation. Figure 79 shows the average demand forecasting errors for minimum, afternoon peak and evening peak demands. Between 2009 and 2011 the relatively high errors can be attributed to inaccurate wind generation output forecasting. As more precise models and weather data became available, the error gradually decreased until late 2011-early 2012 when uptake of solar PV started.

Figure 79
Historic Demand Forecasting Error



With no significant amounts of storage solutions currently present to make the net demand curve smoother, the demand curve throughout the day will change shape dramatically in future years with continued growth in EG. This in turn will mean any historic demand will have to be corrected to account for embedded generation, therefore the embedded generation power curve models and accurate weather forecasts will be crucial to allow demand forecasting to be accurate enough for efficient real-time system operation.

Demand Forecasting with High Levels of Embedded Generation

6.5.2 Work in Progress

In some of the Future Energy Scenarios (FES) there is the potential for high levels of heat pump, electric vehicle and other new domestic technologies. These will inevitably change the characteristics of underlying demand. National Grid is currently leading several research projects looking at the impact of these new developments to understand that impact on demand forecasting in the longer term. Most notably, the Electricity Demand Archetype Model 2[22] (EDAM2) project is bringing together learning from several earlier projects to build more accurate residential and non-residential demand models and build the view of future demand characteristics from the bottom-up. There are also five projects focusing on forecasting and increasing the predictability of wind power output:

- UK-wide wind power: Extremes & Variability[23]
- Impact of extreme events on power production at the scale of a single wind farm[24]
- A combined approach to wind profile prediction[25]
- UK regional wind: extreme behaviour and predictability[26]
- Clustering effects of major offshore wind developments[27].

On the distribution side, the Low Carbon London[28] project has made great advances in understanding the impact of electric vehicles and heat pumps on consumer demand, power quality and optimisation.

[22] Energy Networks Association website. Electricity Demand Archetype Model 2 [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1305

[23] Energy Networks Association website. UK-wide Wind Power: Extreme and Variability [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1443

[24] Energy Networks Association website. Impact of Extreme Events on Power Production at the Scale of a Single Wind-farm [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1463

[25] Energy Networks Association website. A Combined Approach to Wind Profile Prediction [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1602

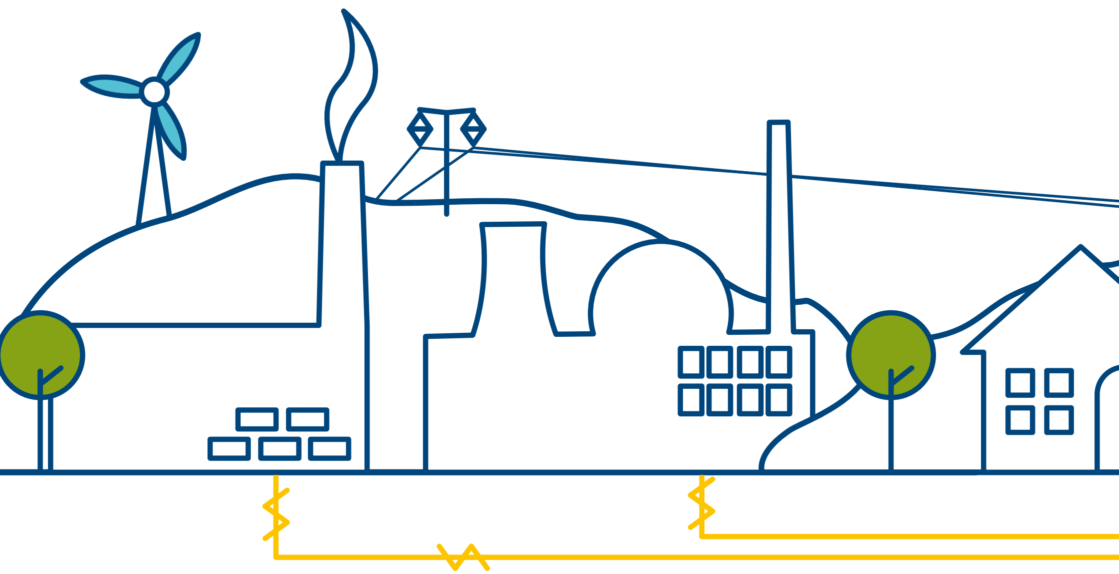
[26] Energy Networks Association website. UK Regional Wind: Extreme Behaviour and Predictability [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1421

[27] Energy Networks Association website. Clustering Effects of Major Offshore Wind Developments [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1446

[28] UK Power Networks website. Low Carbon London [Online]. Available: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/

6.5.3
Mitigating Options

The increase of embedded generation capacity in recent years changes the net demand profile dramatically. The lack of visibility of a large amount of EG operational information from a System Operator's view bring challenges for accurate demand forecasting which may impact the real-time operation of the power system. In order to improve the accuracy of future demand forecasting, National Grid will work closely with EG companies and research organisations to build more accurate demand models and better outline future demand characteristics.



Chapter 7
New Technologies

Key Messages

Sub-Synchronous Resonance and Torsional Interaction

Control System Interaction and Coordination

New Nuclear Capability

Demand Side Technologies

Key Messages

7.1
Key Messages

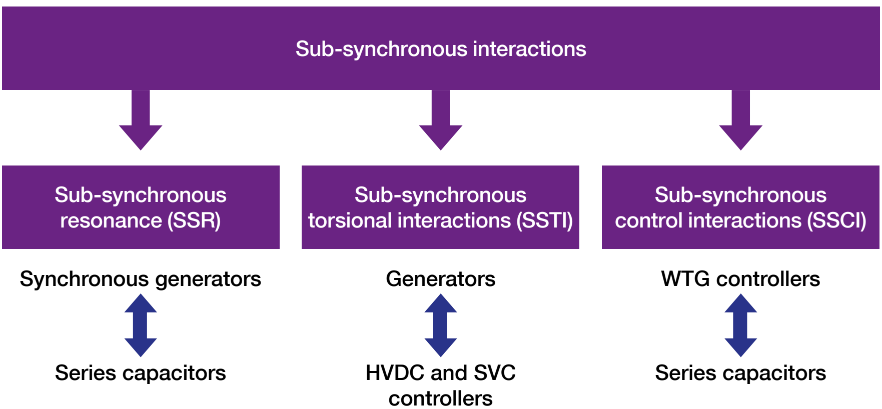
- New nuclear technologies like the European Pressurised Reactor (EPR), Advanced Boiling Water Reactor (ABWR), and Advanced Pressurised Water Reactor (PWR) need careful considerations from a Grid Code compliance perspective concerning their role in frequency response and load following, voltage control, system stability, and emergency system restoration. This is especially important when the level of nuclear and renewable generation will exceed minimum demand when the ability to de-load regularly will be crucial
- The increase in demand side technologies such as electric vehicles, heat pumps, and energy storage (only electrical storage is considered in the SOF) will necessitate closer collaborations between Transmission and Distribution companies as well as wider industry to perform various impact assessments on power networks.

Sub-Synchronous Resonance and Torsional Interaction

7.2
Background

The Sub-Synchronous phenomena can be classified into three categories as illustrated in Figure 80. Sub-Synchronous Resonance (SSR) occurs due to the addition of series compensation onto the system and Sub-Synchronous Torsional Interaction (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 very severe cases they can both cause generator shaft fatigue and failure. Sub-Synchronous Control Interaction (SSCI) is discussed in a separate section further in this chapter. Other types of Sub-Synchronous Interactions exist between control systems and the transmission network, and between control systems at particular complementary control frequencies; these will become increasingly relevant as regional levels of non-synchronous generation increase.

Figure 80
Sub-synchronous Interaction Classification



Sub-Synchronous Resonance and Torsional Interaction

SSR/SSTI in this context has been assessed through a methodology and a framework developed within National Grid which takes advantage of the previous work done by our consultants and contractors. This work usually requires close co-operation with the generators that could potentially be affected by SSR/SSTI, since accurate generator shaft system data is required to carry out the assessments and to design the appropriate mitigation solutions.

The focus in this area is on turbine-generator shaft system of power stations close to series compensation and HVDC links. Key findings from these assessments will provide an indication of the extent of potential operability concerns and how they can be mitigated.

7.2.1 Impact on Operability

In the case of the series capacitor, if the complement of the transmission network electrical resonant frequency (50-fe Hz) is close to or coincides with one of the turbine-generator shaft natural frequencies of synchronous generators, SSR will take place. This can result in shaft oscillations subject to the level of mechanical damping present in the shaft to restrict such oscillatory behaviour. If not damped in good time, SSR can damage the turbine-generator shaft resulting in loss of generation.

The potential for SSR to occur increases with the increase in the level of series compensation and also at low system demand and when there are certain circuit outages in close proximity to the series compensation.

The risk is similarly higher when synchronous generators are radially connected into the network near the series capacitors. Typically only thermal power plants are at risk of being exposed to SSR as hydro generators usually have a different shaft design which makes them immune to SSR.

In the case of HVDC installations there is a possibility of a similar but different interaction called SSTI. This arises as a result of the time difference between the current and active power feedback loop of the HVDC control system and the turbine-generator shafts of neighbouring synchronous generators. This can also result in shaft oscillations, though on a smaller scale than the series capacitor interaction.

7.2.2
Assessments and Key Findings

Preliminary studies are carried out and mitigating measures are implemented in the early design stages of HVDC links and series capacitors to eliminate operational restrictions and allow optimal utilisation of these technologies. These assessments require complex system models that are continuously improved and updated.

In order to ensure that potential SSR/SSTI risks are managed, National Grid has developed a study framework for its assets that covers (for both series capacitor SSR and HVDC SSTI):
- Screening studies to determine if there is a resonance condition;
- Calculation of shaft natural frequencies and damping to determine if there is a potential of interaction between the shaft system and electrical network (these studies require generator shaft data for the specific generators); and
- Studies to determine SSR and SSTI mitigation measures.

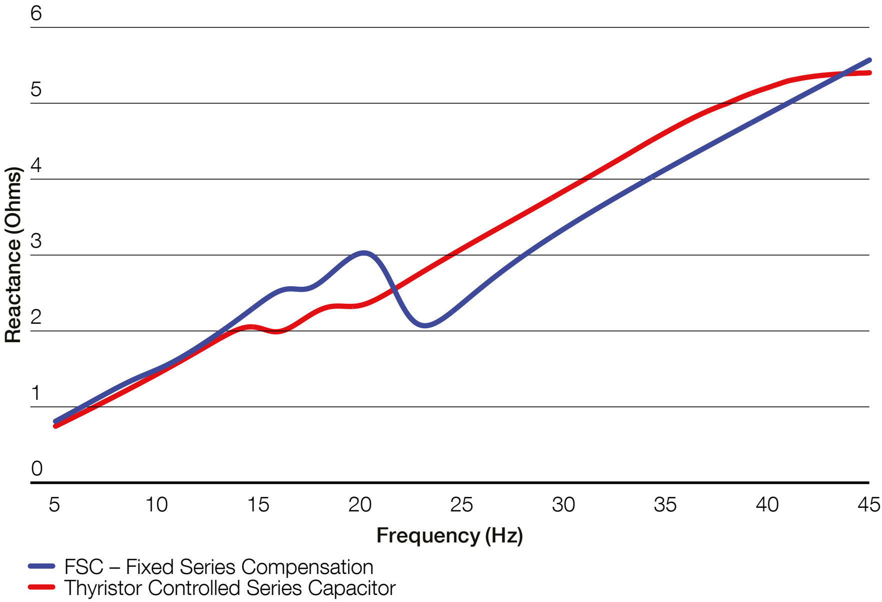
These assessments (as well as an annual network scan which ensures validity of the results on enduring basis) will be carried out, and the mitigating measures such as modification to the control systems or addition of a new control system will be recommended. Studies relating to the Unit Interaction Factors (UIF) for HVDC connections are already routinely carried out at the connection design stage. Furthermore, a full suite of Electro-Magnetic Transient (EMT) analysis is carried out by taking into account the performance of the links and interaction with generators' shaft. There is a dependency on the availability of the generator shaft data, and where such data is readily not available, other avenues, such as site tests, may need to be pursued to obtain the necessary data.

Some of the key findings from these projects are presented in Figures 81 and 82 for illustration.

- The presence of reactance dip greater than 5% in a frequency scan is usually an indication of a potential SSR problem. This is illustrated in Figure 81 which shows the parameters for a Fixed Series Compensation (FSC) without a damping filter. The Thyristor Controlled Series Capacitor (TCSC) solution by NGET has mitigated the dip, and hence mitigated the potential SSR problem. The use of FSC with damping controller can also mitigate the risk of SSR.

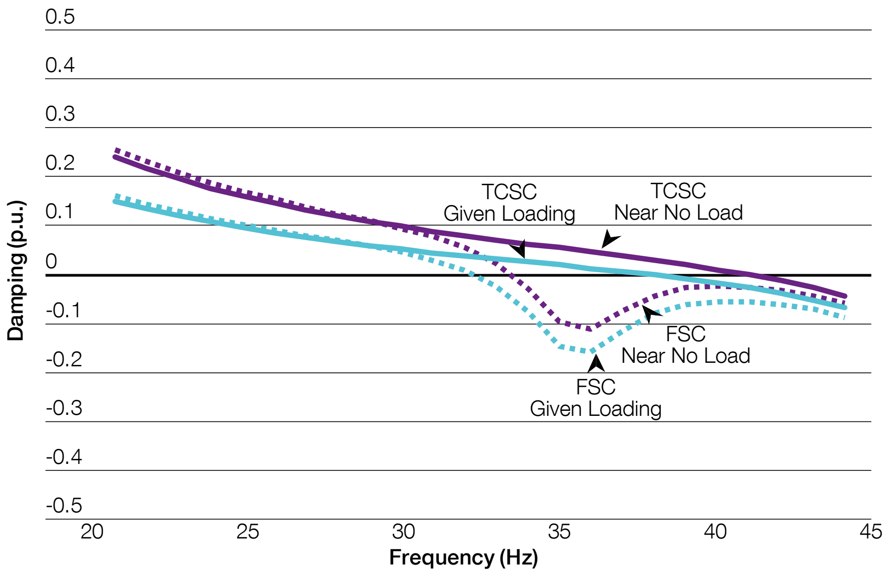
Sub-Synchronous Resonance and Torsional Interaction

Figure 81
Frequency Scan of a Network with FSC (no SSR filter) and TCSC with SSR Control



- The calculation of electrical damping versus sub-synchronous frequencies is shown in Figure 82. The torsional frequencies and the effect of machine loading are also shown in these curves. It is noted that when using an FSC (without a damping filter), the electrical damping is negative for some modes and there is a resonance condition. In this case, SSR would take place if the negative electrical damping exceeds the positive mechanical damping. However, the TCSC not only mitigates the resonance condition but contributes to the damping as well. So the result for TCSC is a positive electrical damping for all modes below 38Hz mechanical frequencies (or above 12Hz electrical frequencies – it covers the range of mechanical frequencies of concern) and mitigation of the SSR-TI phenomenon. The effect of mechanical damping is not considered in these calculations. The combined effect of electrical and mechanical damping should provide positive damping over all of the concerned range of shaft mechanical frequencies. An FSC with SSR damping filter is expected to provide similar positive damping (not shown in this Fig).

Figure 82
Electrical Damping Versus Torsional Frequencies for Different Loadings (FSC without SSR filter, TCSC and SSR control)



- In case of the HVDC links; based on the technology (LCC or VSC), various screening studies are carried out. In general, a LCC based converter in the rectifier mode could have interaction with generators' shaft. In case of VSC based converters this effect, based on manufacturers' report is very limited, but still requires the scanning studies in the inverter mode. In summary; the HVDC links connected to GB power system (interconnectors, or embedded HVDC links) will be designed / operated in such a way that they will not cause SSTI.

Sub-Synchronous Resonance and Torsional Interaction

7.2.3
Work in Progress

The following transmission reinforcement projects addressing the SSR/SSTI concern are currently under way:

- The Thyristor Controlled Series Capacitor (TCSC) at Hutton substation was commissioned in February 2015 – The use of TCSC will eliminate the risk of SSR;
- Scottish Power Transmission (SPT) have installed Fixed Series Compensation (FSC) at Moffat, Gretna and Eccles with passive SSR damping filters; and
- Western HVDC link project between Hunterston (Scotland) and Flintshire Bridge (North Wales) with SSTI damping control will be commissioned.

National Grid is currently working with a number of international TSOs, and academic institutes to share the best practice in this domain, and particularly enhance the modelling capability required in this area.

7.2.4
Mitigating Options

There are a series of studies that National Grid would normally undertake to identify possible future issues/risks under the study framework outlined above. 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 and Torsional Interaction. Technical Guidance Notes (TGNs) have been produced to help study series compensation SSR impact, the HVDC SSTI impact, and the operational regimes for the Control Room operators.

Based on international surveys and studies by National Grid and our consultants, we decided to choose a capacitor based solution for their Hutton series capacitor project (a TCSC solution employing the SVR technique). Similarly for the Western HVDC CSC Link project, a decision by the Joint Venture was taken to employ SSTI damping controller at Flintshire Bridge and Hunterston converters.

Control System Interaction and Coordination

7.3 Background

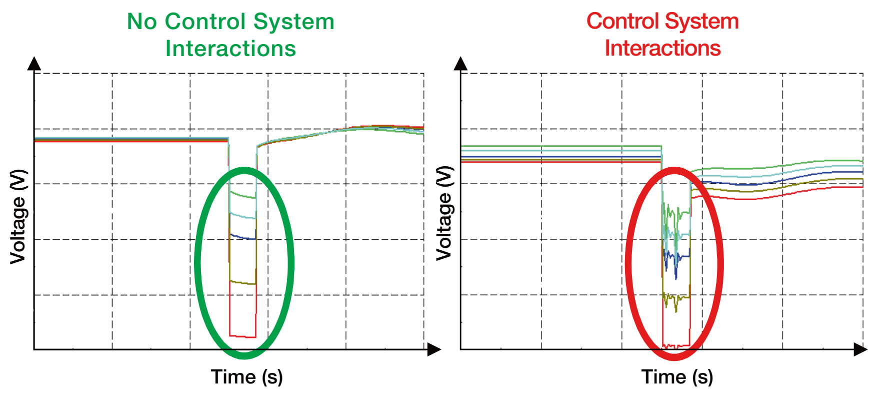
Power electronic control systems used in Static VAr Compensators (SVCs), FACTS devices and wind turbine control systems, particularly Doubly Fed Induction Generators (DFIGs) radially connected to a series compensated transmission circuit, can interact with sub-synchronous modes of the network and cause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

The control system interaction can be more likely when these devices are electrically close to each other or on the same bus bar. The interaction can be different in different regions, and therefore the operational co-ordination of these devices is important for their effective use and to resolve certain network constraints (thermal, voltage or stability).

With the increasing number of non-synchronous generators, FACTS, and HVDC converters connected electrically very closely together, and all having control systems which share similar input values (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 could occur.

Control system interaction for particular areas of concern in this context is assessed through analytical studies using power system dynamic models of FACTs and HVDC systems. Availability and suitability of tools and data is an issue, and National Grid is committed to work on it. Advantage will also be taken of the work done by our consultants and contractors. Key findings from these assessments should provide some indication of the extent of potential problems and how such problems could possibly be mitigated.

Figure 83
Control System Interaction



Control System Interaction and Coordination

7.3.1
Impact on Operability

Some key areas that will see an increase in the connection of highly sophisticated control systems have been identified and summarised below. The interactions of these control systems need to be studied as soon as possible particularly in the early design stage:

- South East: connection of NEMO HVDC, Eleclink HVDC, and new SVCs, along with existing wind farm HVDC links (mainly considering interconnectors and East coast offshore wind farms)
- North Wales: large number of new wind farm connections in proximity of East-West (EirGrid) 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 (mainly considering offshore wind farms);
- Scotland: new VSC HVDC connections in areas of low system strength.

The impact on operability in severe cases could mean over-voltages, current distortion, tripping of additional facilities and potential damage to control systems.

7.3.2
Assessments and Key Findings

In the case of the South East, 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 based on the current FES. For North Wales there is a potential for more extensive co-ordination assessment after the Western HVDC link is commissioned in 2017.

Some interaction studies for the South East HVDC links were carried out with the aim to assess SSTI and how CSC/VSC controllers might damp the interaction with generators at Dungeness. It was found that the CSC controller mode frequency is sensitive to integral gain, and the damping is sensitive to the proportional gain. Therefore the interaction with generator torsional frequency can be minimised by adjusting the CSC controller gains. Similarly when a VSC HVDC is in place, its power/current controller gain can be adjusted to provide positive damping. For the South East, studies also indicated no SSR or interactions between the HVDCs and wind farm Statcom controllers, or with the external network. We aim to revisit these studies from time to time when system conditions change to ensure these interactions do not arise in the future.

In addition, National Grid has investigated the active and reactive power recovery and rotor angle stability after a fault for link import and export conditions when CSC and VSC HVDC links are in close vicinity to each other. This work however needs to be extended to use project specific HVDC models and data in order to properly investigate the torsional and control interaction aspects.

Possible areas for interaction studies between CSC and VSC HVDC links are:
- Parallel operation of CSC and VSC HVDC links during start-up and shut-down, assess control system interaction for filter switching, effect on voltage step and reactive power exchange
- Loss of VSC HVDC impact on CSC commutation
- Pole and mode switching – instability assessment
- Insulation coordination (energy rating of bus arresters).

National Grid has sponsored R&D work to study interaction between series capacitors and wind turbine control systems (to be completed by March 2016). The analysis has investigated the following aspects so far:
- The impact of wind farm in a series compensated network
- The impact of synchronous machines in a series compensated network (with no wind farms)
- The combined impact of wind farm and synchronous machines in a series compensated network.

Some of the findings from this work are outlined below:
- For a DFIG machine, the voltage components of Series Compensation and the current components of the network (including wind generator stator and rotor) contribute to the development of SSR. A properly designed SSR damping controller can mitigate this effect
- As the Full Converter (FC) machine decouples the turbine from grid side, oscillations from grid side will not impact the wind turbine. However, the analysis shows a marginal case for the damping which is probably due to the data accuracy
- Results from the steady state (small signal) analysis and dynamic simulations of DFIG and FC wind farms for different levels of series compensation show different modes of oscillations with increased compensation levels. There are levels of compensation when shaft torsional frequencies would interact with the network.

The table overleaf summarises the impact of each of the FES scenarios on the aspects associated with control system interaction and coordination.

Control System Interaction and Coordination

Table 5
Control System Interaction and Coordination Requirements

Region	Gone Green	Slow Progression	Consumer Power	No Progression
South East	Greater need for co-ordination expected in 2017/18	No additional mitigation requirement expected until 2018/19	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected until 2019/20
North Wales	Potential for more extensive control co-ordination after 2016			
East Coast	Triggering events expected in 2019-20	No additional mitigation requirement expected until 2024/25	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected before 2035/36

7.3.3 Work in Progress

The following work is in progress:

- Control interaction for parallel operation of CSC and VSC HVDC links during start-up and shut-down, reactive power exchange between the DC-AC systems, filter switching, and the effect on voltage step changes
- Control interaction between wind-farms and series compensated network, and the design of damping controller.

7.3.4
Mitigating Options

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 modelling, and without representative models it is 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.

Currently, a lot of data is gathered through the Wide Area Monitoring Systems (WAMS) using PMUs, but the latest VISOR Project findings indicate the quality of data is poor in some places, other places have missing data, and some places need more PMUs installed. Several events have been analysed from this data, including the performance of recently installed monitors on the Harker-Hutton circuits coincident with the TCSC installation, which have helped assessing the sub-synchronous oscillation issues there. It is expected that the use of this data will be extended to validate dynamic models used in our power system studies so that future performance of the Transmission System can be better evaluated. It is possible these studies might need more or different signals and signals from other locations not monitored yet – all this will be investigated as required.

New Nuclear Capability

7.4 Background

New nuclear technologies expected to connect to the GB transmission system in the future have been developed to meet international requirements with different regulation philosophies, system sizes and level of inertia compared to GB.

Most existing nuclear plants were connected when the electricity industry was nationalised and as such were not required to comply with Grid Code requirements, however, these conditions generally refer to existing gas-cooled and advanced gas-cooled reactors, (Grid Code OC2.4.4.2 and BC3.5.3). The provision of additional response capabilities is agreed between nuclear plants and the GB SO, provided nuclear safety case approval for such modes of operation have been first sought and agreed to by the Office for Nuclear Regulation (ONR). As a result, all of the existing gas-cooled plants have a limited existing provision of frequency services, restricted to frequency following capability under Limited Frequency Sensitive Mode of operation.

The existing (connected) and new nuclear technologies (not yet connected) are shown in Table 6.

Table 6
Existing and New Nuclear Technologies

Technology	Status	Number of plants	Number of generating units
Magnox	Existing	1	2x250MW
Advanced Gas Reactor (AGR)	Existing	8	2x660MW
Pressurised Water Reactor (PWR)	Existing	1	2x660MW
European Pressurised Water Reactor (EPR)	New	3	5x1670MW (1800MW gross of station demand)
Advanced Boiling Water Reactor (ABWR)	New	2	4x1170MW (1350MW gross of station demand)
Advanced PWR 1000	New	1	3x1129MW (1200MW gross of station demand)

The new nuclear plant technologies currently applying for connections to the GB transmission system all represent 3rd generation nuclear technologies which have evolved from past international and learning experience. None of these power stations are based on existing gas-cooled or advanced gas cooled technology which may currently operate without frequency services. These designs and technologies are different from the existing breed of nuclear plants connected to the GB transmission system, although two of the new designs – the AP1000 and EPR – are of a Pressurised Water Reactor design in common with the newest of the existing nuclear plants connected (Sizewell B), which is not subject to those exclusions within the Grid Code referenced above.

New nuclear technologies are being assessed from GB Grid Code compliance point of view, especially in the area of frequency/load following, fault ride through, voltage control, system stability and emergency system restoration.

7.4.1 Impact on Operability

Nuclear plants have potential advantages in offering higher inertia which contributes towards improved system stability and system frequency performance, good voltage support through their reactive power range (provided it may be utilised) and a more predictable output than renewable generation sources. However, because the new nuclear designs have been developed to meet international requirements, National Grid, potential new developers and regulators are engaged in the process of ensuring that such new designs are GB Grid Code compliant.

7.4.1.1 Frequency Response

During periods of low demand where the volume of interconnectors, embedded generation and wind generation could exceed demand, nuclear plant connected to a future system would be expected to support the frequency response requirements of the wider system. This would be a key consideration given the economics associated in de-loading nuclear plant across such periods as an alternative to the costs and uncertainties associated with the alternative of switching off nuclear plant. Consideration should also be given to the potential to constrain off embedded distributed generation and the ability to constrain micro generation under normal operational conditions. Solutions involving energy storage and demand side management responses at these times also provide possibilities, as would the framework to enable HVDC interconnector action such as de-loading or reversal. Against Future Energy Scenarios which show periods of low transmission system demand, new nuclear plant would be expected to operate in a Frequency Sensitive Mode (FSM) at times when it is economic and efficient to do so. As discussed in other SOF sections, these options carry both costs and technical challenges.

New Nuclear Capability

At low demand periods, generation that usually provides frequency response may not be running. In this situation, nuclear and wind would not deliver the required response. This issue may also be exacerbated due to low inertia (which results in a higher rate of change of frequency – RoCoF) and the broader impact of RoCoF on nuclear units ability to remain connected. Following new nuclear build, the combined loss from two generators could potentially exceed the SQSS allowed largest infeed loss of 1800MW. The remaining nuclear plants will be required to withstand and remain connected to the system, even if services from those power stations are not required at the time.

The new nuclear connections, like the previous nuclear technologies, are also expected to offer good inherent inertia and damping, a useful inherent facility for contributing to system stability following a transient disturbance on the GB Transmission System.

7.4.1.2 Fault Ride Through

As noted above in the short circuit level section, fault levels on the system are expected to decline significantly in future, however the extent of this decline and its scale may be reduced in areas of high future nuclear generation connections. Against this context, future system voltage dips will result in a more extensive area of voltage depressions than currently observed across the transmission network. Again, new nuclear will have a critical role during such periods. In addition to including large generator unit sizes in their design, nuclear generation technologies require significant auxiliary supplies from the transmission system (for example the largest of these stations, the EPR, requires some 130MW of demand per reactor for the cooling system and other site auxiliary supplies). In order to ride through transmission system fault conditions, these supplies need to remain resilient to the same fault conditions (i.e. transmission system faults cleared in main and backup operating times) and support the recovery and response of the overall power station.

Noting both the extent of the voltage depression contours described in other sections of the SOF, and the natural tendency for two or more identical generator and reactor designs to be connected at the same or close electrical points, it is essential that new nuclear power stations are considered both individually and collectively in order to ensure practical resilience and overall system robustness.

7.4.1.3 **Voltage Control**

Voltage control and reactive power provision is an essential requirement from nuclear power stations as it is for other types of generation. The challenges associated with nuclear power stations providing voltage control and reactive power which are associated with the size of the generator and require particular attention are summarised below:

- New nuclear power stations are in close proximity to the existing nuclear sites and are generally at strategic points on the network which is an important criteria for network voltage support
- Each individual generating unit is now of such scale that voltage support could become problematic, both due to the design of the generator transformer and tap changer and the effect that a generating unit trip could have on the Transmission System, particularly in respect of voltage step change issues
- Energising the generator transformer of such large new nuclear power stations may present an issue. The energisation inrush that may accompany such action may cause voltage fluctuations and limit the flexibility of the unit operation under certain circumstances.

7.4.1.4 **Emergency System Restoration**

Currently existing nuclear plant does not in general play an active role in the Black Start of the transmission system. There are some limited cases where nuclear plant has been designed to, or is capable of islanding with load potentially disconnected with the power station, which could reduce the scope of Black Start requirements in these instances.

Decline in the availability of synchronous generation across minimum demand and other times can present a challenge in developing new approaches and a new portfolio of services for black start.

As part of the work undertaken under the "Black Start Alternative Approaches" NIA work[29] and our involvement in the Emergency and Restoration EU Code, we are aware that in continental Europe existing nuclear plant commonly employs a "trip to house load" operation. This seeks to develop a power island relating to the nuclear plant and its unit supply that can then be used to support restoration of larger power islands. At least one of the three nuclear designs currently being considered would be subject to these same considerations. Under Grid Code provisions, new nuclear build should be capable of islanding with a load of at least 55% of its registered MW capacity. Out of all synchronous generation resources, new nuclear power plants are expected to be uniquely available at all times and across all FES scenarios and so have a significant role to play in providing restoration services both to the benefit of the existing fleet and wider system restoration.

[29] Energy Networks Association, Smarter Networks Portal, Black Start Alternative Approaches [Online]. Available: http://www.smarternetworks.org/Project.aspx?ProjectID=1653

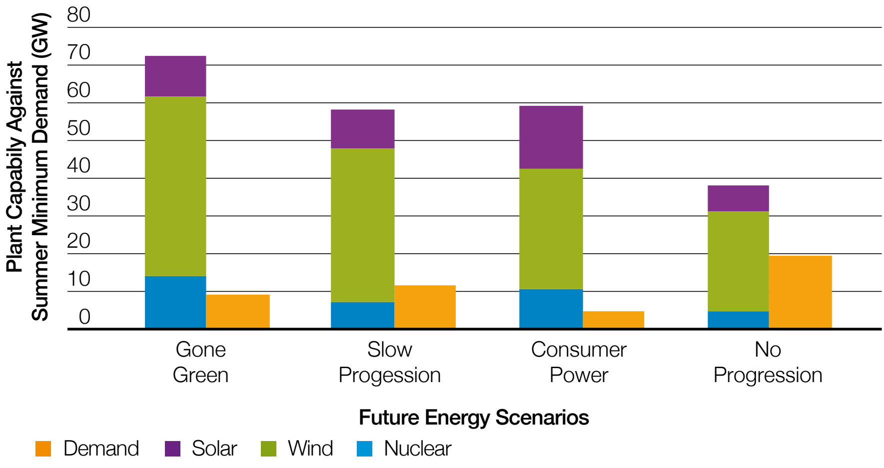
New Nuclear Capability

7.4.2
Assessments and Key Findings

Based on the FES scenarios from 2021 onwards, the level of nuclear and renewable generation will exceed minimum demand conditions, as shown in Figure 84. Under these conditions it will be necessary to consider the response and reserve capabilities of both of these technologies against the backdrop of changing transmission system needs. The ability of plant to regularly de-load will be crucial and plant without sufficient load following capability and Designed Minimum Operating Level (DMOL) may not be sufficiently flexible to operate at times. As a consequence, if the minimum shutdown period is comparable to current nuclear plant capabilities, this could lead to extended periods where relatively inflexible plant is unable to operate. As such, it is important to consider and highlight the Grid Code requirements which form the baseline for performance, the opportunities which enhanced performance would bring, and note the range of technical options appropriate to the integration of these technologies.

Figure 84 shows that based on the maximum allowable Designed Minimum Operating Level (DMOL) of 55% of Registered Capacity (as specified under the Grid Code), not all nuclear power stations would be able to operate even at full de-load, unless lower de-loading levels were agreed (no higher than 45% of registered MW capacity). Such allowance provides load balancing only and takes no account of securing the largest loss at that time via the use of frequency response services, nor the balancing impacts that would surround these requirements.

Figure 84
Summer Minimum 2035/36 Plant Capabilities and Demand



As shown in Table 6 above, new nuclear designs will be between 1.8 to 2.7 times the size of the current largest nuclear generators. When completed, these generators will represent the largest single synchronous AC connections on the GB transmission system. In 2008, under GSR007, the NETS SQSS was modified, increasing the infrequent infeed lost risk from 1320MW to 1800MW enabling these and other larger scale connections. As discussed within other SOF sections, the levels of frequency response holding will need to change as these and other larger scale connections come into place. At these times, either the maximum infeed loss risk at the time will be secured, or the large units will be de-loaded where that represents a more cost effective solution.

Uniquely, new nuclear connections, being single large generators, are limited in their de-load capacity. Under the Grid Code, the DMOL of any generating unit should be no more than 55% of Registered Capacity. This will mean that in the future, the largest loss at times of minimum demand will be dictated by new nuclear generation, which raises challenges around reserve and response handling. Based on the largest loss of 1800MW this means that such units could only be reduced to a loading level of 990MW, a level which as can be seen in other SOF sections may continue to present a challenge.

7.4.3 Work in Progress

Investigations by new nuclear developers and National Grid indicate that there are some challenges in meeting the requirements of the Grid Code which may require some alterations to the standard design. These areas have been individually discussed with each manufacturer/operator and it has been identified that deviations from the standard design may impact on the Generic Design Assessment (GDA) undertaken by the Office of Nuclear Regulation (ONR). Further discussions regarding the potential impacts of the Grid Code and non-compliance need to be discussed with all new nuclear build parties including National Grid, Ofgem, ONR & DECC. The approach taken by nuclear companies is to:

- Work with National Grid to put in place engineering solutions where it is technically and economically feasible, and design changes that satisfy the ONR requirements
- Consider modifying the running regime of the plant to minimise impact on GB Transmission system operation
- If the above are not achievable, consider and seek derogations against the Grid Code requirements.

Meeting ONR requirements is a high priority, and it must also be recognised that meeting Grid Code is a key GB regulatory requirement.

New Nuclear Capability

7.4.4 Mitigating Options

As the impact of design uncertainties is not fully known, the exact nature of mitigation measures and cost is not yet clear. However, from discussions with nuclear companies, major changes to the GDA could prove to be prohibitively expensive such that some of the options and approaches discussed above may be required.

The following summary of some possible mitigation solutions could be considered, depending on the effectiveness of each measure and the cost level. These are summarised in Tables 7 and 8.

Table 7
Generator Side Possible Mitigations and Solutions

	Changes to generator plant	Changes to reactor/ steam plant	Derogation and/ or Grid Code modifications	Change ancillary equipment
Response/ reserve		✓		
Fault ride through	✓			✓
Voltage control	✓		✓	✓
System stability	✓			

Table 8
Transmission and Wider Industry Possible Mitigations and Solutions

	ONR Interaction	Transmission reinforcements	Generator terminal voltage control	Third part provisions of mandatory service
Response/ reserve	✓			✓
Fault ride through	✓	✓		
Voltage control		✓	✓	
System stability	✓	✓		

Demand Side Technologies

7.5
Background

In this section the impact of some of the new demand side technologies such as electric vehicles, and distributed connected energy storage are studied. The grid planners and operators have limited operational experience of these technologies similar to the large scale transmission connected new technologies. In addition, the lack of visibility, and direct control on these technologies may increase the operational challenges, should there be a grid impact.

Whilst the data available and the assessment methodologies used for operability assessment of the earlier topics are more widely available and more developed, due to the nature of the technologies studied in this section, there is not a defined industry approach or standard to assess their impact. The analysis in this section, whilst has gone through the same assessment process as other sections, is an illustrative assessment and is intended to form the basis of future collaborations to enhance the study capability in this area.

7.5.1
Impact on Operability

Electric Vehicles

The electrification of heat and transport, as forecasted by FES, will increase the demand for electric power. There are a number of aspects to this change and in this section we have only considered the impact on power networks and how system balancing may need to be reviewed in this context. The fundamental differences of heat pumps and electric vehicles (EV) compared to other type of demand are:

- Both heat pump and EVs are significantly bigger loads in the domestic sector compared to traditional loads;
- Their operation can be less diverse (high coincidence factor) both in terms of time, and location;
- The rapid development of the technology used in these loads (i.e. new super-fast charging stations) will change the characteristics of these loads and the use of historical data may be less effective for the purpose of studies and decision making.

The large increase in the take-up of both EVs and heat pumps can bring a number of fundamental challenges for the system:

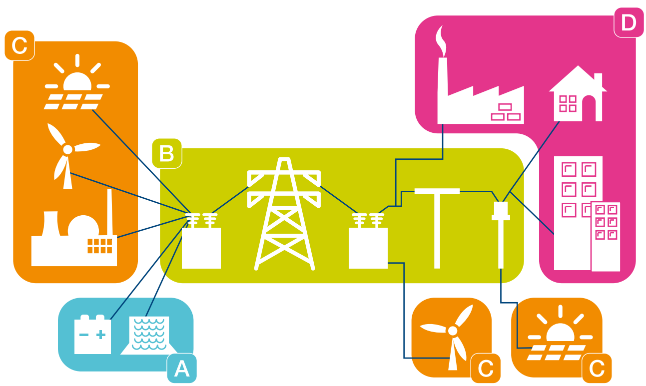
- The power networks may not be capable of accommodating these technologies due to capacity and congestion issues
- Potential increase in demand and insufficient flexibility in the balancing market can make the balancing of the system more challenging and potentially inefficient if the parallel utilisation of demand side services is not possible.

Demand Side Technologies

Energy Storage
Unlike EVs and heat pumps, and regardless of the financial viability of each model, there are different models for the use of Energy Storage on the system:

- Model A – Grid scale storage only: large scale energy storage facilities (such as pumped storage) which offer grid flexibility (mainly for balancing purposes) and can participate in other ancillary services
- Model B – The network based Energy Storage
  - Model b1: Distribution connected energy storage: where the energy storage units are installed on the distribution network, and they can assist with managing network constraints, as well as exploring the other revenue streams
  - Model b2: Transmission connected energy storage: where the energy storage units are installed on the transmission network and are therefore likely to be significantly greater in size, and they can assist with managing network constraints, as well as exploring the other revenue streams
- Model C – The hybrid generation-energy storage: where the energy storage units are installed in proximity of a generation site, and is intended mainly to increase the availability of services from the generation (in the energy market, or ancillary services), or for wider system benefits (to avoid curtailment)
- Model D – The consumer based energy storage: where the energy storage devices are intended mainly for energy efficiency, maximising the use of on-site generation, or resilience purposes.

Figure 85
Energy Storage Models



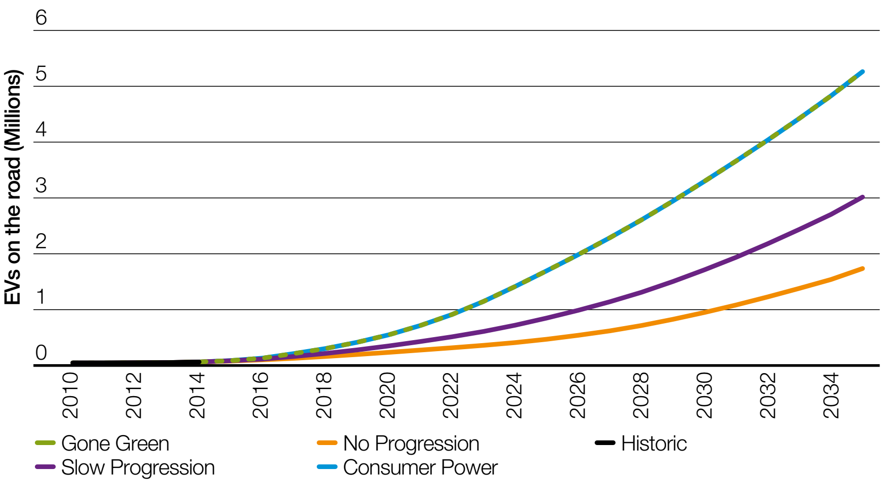
Model	Operational Experience in GB
A	Large scale pump storage units (synchronous generator)
B1	Limited number of trials by distribution companies, and academia into the use of energy storage of various forms (battery, compressed air, super-capacitor, flywheel)
B2	None
C	The trial as part Enhanced Frequency Control Capability (EFCC) by National Grid
D	None (apart from limited use of battery storage an emergency backup power supply)

In GB, there are number of grid scale energy storage technologies (pump hydro) and more recently a small number of trials of using other forms of storage such as batter storage have been conducted. There are however very limited GB experience of model B, C, and D. All above models in addition to the benefits they bring to the grid, will have impact on operability which are studied in this section.

7.5.2
Assessments and Key Findings

Electric Vehicles
FES 2015 shows the highest take up rate of electric vehicles in Consumer Power scenario as shown in the figure below.

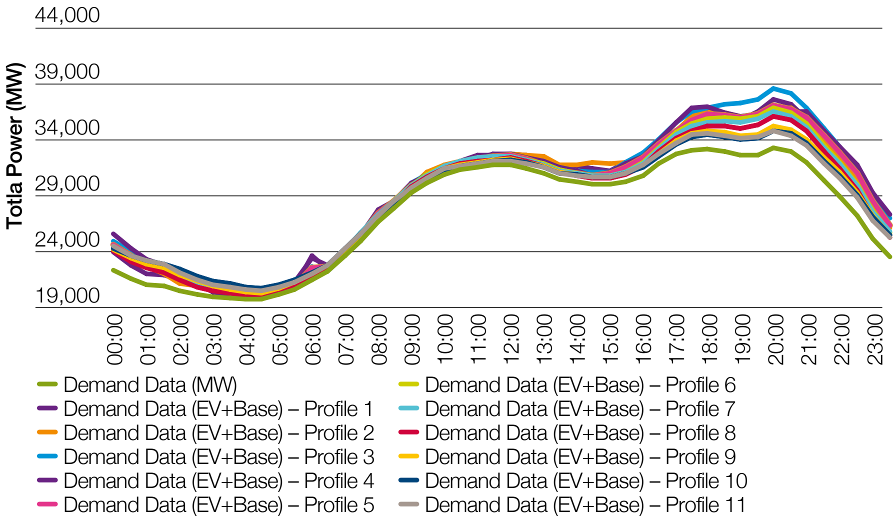
Figure 86
Take up rate of Electric Vehicles



Demand Side Technologies

In Consumer Power scenario, the maximum take up rate envisaged for electric vehicles is just over 5 million EVs by 2035. In terms of the impact on the network, the other factor which is important to study is the amount of power they may draw from the system. This is dependent on the size of the charging modules. The size of the charging stations is currently between 3kW–7kW. There are however fast charging units up to 20kW which consume significantly more power. We have used the data from a number of previous trials on the use of electric vehicles and different charging patterns, and the impact that the daily profile of the various charging pattern will have on the system.

Figure 87
Impact of Electric Vehicles on Daily Load Profile



Our analysis shows that the impact of EV charging will be mainly on the distribution networks (localised). Due to the diversity of the EV technologies and the capacity of the grid supply point transformers and the transmission network itself, the impact on the transmission network to the level identified in FES is not much of a concern.

From energy balancing perspective, at high penetration level of EVs, the diversity (as seen in the trials) in EV charging will eliminate the “sudden” load pickup. However, the load profiles studied for a typical summer day show greater need for demand side management to avoid steep peaks and valleys in the demand profile.

Energy Storage

FES 2015 does not explicitly present the volume of energy storage for models other than model A. It is therefore not possible to perform a quantitative impact assessment similar to what has been done for all other topics in the SOF. However, considering the different energy storage technologies a qualitative assessment was undertaken and is summarised in the table below:

Table 9
Operability Challenges associated with Energy Storage

Model	Network Constraints	Power Quality (Technology Dependent)	Reduction of System Inertia	System Balancing Challenges	System Security
Model A: Grid Scale	High (need for full spare infeed/ outfeed capacity)	Minimal (if captured by grid code)	High (in generating mode) whilst it can help by creating headroom in charging mode	Minimal	Minimal (contributor to system security)
Model B1: Network Based; Distribution	High if uncoordinated whereas can offset reinforcement	Minimal (if capture by distribution code)	Same as above (only at high penetrations)	High if not coordinated and at high penetrations	High (is landing operation)
Model B2: Network Based; Transmission	High only if uncoordinated and if intended to be embedded	Minimal (if captured by grid code)	Same as above (only at high penetrations)	High if not coordinated and at high penetrations	Minimal
Model C: Hybrid Generation-Storage	Minimal (can offset the need for reinforcement)	Minimal	Same as above (only at high penetrations)	Minimal (it assists by smoothing the generation profile)	Minimal
Model D: Consumer Storage	Minimal	High	Minimal	Minimal (assists by smoothing the consumption profile)	High (islanding operation)

As shown above, various different models have different potential operability impacts on the system. By performing whole-system impact assessment before the roll out/take up of different models, the industry can mitigate those challenges. There is a need to update grid codes and develop industry best practice guidelines, if the potential benefits of storage are to be fully captured

Demand Side Technologies

7.5.3 Work in Progress

More improvements and research in understanding the aggregated effect of energy storage, EV charging units and heat pumps is required, as the study carried out in this section used the data from a limited number of trials. We have also conducted a study into the use of charging stations for frequency control purposes, and the benefits it can provide mainly in the balancing domain. In addition National Grid's Enhanced Frequency Control Capability project (awarded by Ofgem as part of 2014 Network Innovation Competition) is investigating for the first time in GB, the feasibility of integration of energy storage with renewable generation to provide frequency response services. This trial will generate significant learning (beyond the specific learnings in managing system inertia) which can inform the stakeholders on operability challenges and opportunities of this roll out model for storage.

7.5.4 Mitigating Options

The lack of controllability of the power consumptions of EVs and heat pumps is the main challenge which can be mitigated by the roll out of smart meters, the ability to spread the charging pattern of EVs and effective use of heat pumps as DSR resources. The size of these loads makes them particularly suitable for better demand side management and provision of the aggregated service to the DSO.
With respect to energy storage, as mentioned earlier, one of the key requirement for less trialled and tested models is coordination and impact assessment. Transmission and Distribution companies should work closely with the developers, and solutions providers to ensure the whole-system effects of such roll outs are considered ahead of any large scale roll out. In addition, the treatment of energy storage in a number of technical codes and standards requires consideration, as do the capabilities expected from these assets under the different models.

Chapter 8
Future Operability Strategy

Future Operability Strategy

Non-Service Based Actions

New Operability Services

Future Operability Strategy

8.1
Future Operability Strategy

In the preceding chapters the detailed assessment results for individual topics are presented, showing variations between scenarios and potential opportunities to enhance system capability. It is evident that in order to define the system needs, and to do so in the most economic and efficient way, a number of challenges should be addressed:

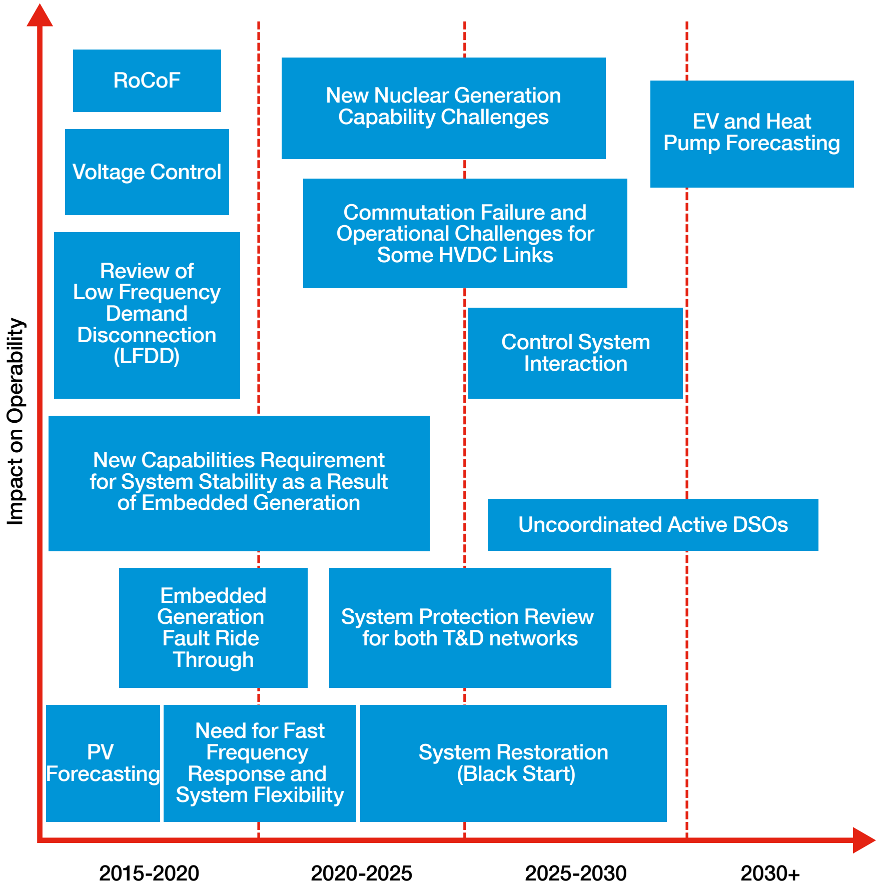
- Identification of capabilities that are needed for different time horizons and the lead time to develop future capabilities
- Identification of common solutions (i.e. technologies or services which can address a number of operability issues)
- Identification of the commercial and regulatory gaps in existing frameworks that slow down the development of future system services.

We held a number of webinars in September 2015 to challenge and review our analysis and to seek feedback from a wide range of stakeholders on the services and capabilities that address future system needs in the context of the SOF. This section provides a summary of the activities, services and actions to address the operability challenges identified in the SOF 2015 and takes account of the extensive stakeholder feedback we received. The purpose of this chapter is to present future operability strategies which set out a pathway for the development of system needs. In presenting various strategies we have differentiated the short-term and no-regret actions from supplementary actions (longer term) when setting out the pathway for the delivery of each solution:

- Short term and no-regret actions highlight the need for immediate capabilities, which are available both technically and commercially or immediate need for code changes. This includes opportunities for engagement with developers and asset owners to utilise the capabilities already available in their plant, which can easily be retrofitted. For some services a number of further assessments have been proposed in this context.
- Supplementary actions highlighted in this section should be kept under review (often dependent on the outcome of the initial steps) and are intended to give better clarity on the further steps in achieving the future system services, or the further trials and research and development opportunities.

Based on the results of the analysis carried out in previous chapters and considering the dependency on the future energy scenarios, the following timeline shows the tipping point of the challenges identified as part of the analysis of this year's SOF. The time range for each challenge is based on the range of scenarios and the impact on operability is based on the analysis we have done to date and the wider views we have received. Some of the topics explored are not included on this figure (i.e. Sub-Synchronous Resonance) as we do not currently see a requirement for new action.

Figure 88
Timeline of SOF Challenges



Based on the timeline a range of activities need to take place. We have presented them in two different categories: non-service based activities (such as code changes) and market based activities (such as new operability services).

Non-Service Based Actions

8.2
Non-Service Based Actions

A number of operability challenges identified in SOF 2015 require changes to various industry codes and standards such as Grid Code or Distribution Code.

8.2.1
Rate of Change of Frequency (RoCoF)

To effectively manage the risk of cascade loss of embedded generation protected by RoCoF relays, a joint Grid Code and Distribution Code Workgroup was formed in 2013. The changes required in RoCoF relay settings have been agreed for generators above 5MW and work is ongoing to address the necessary changes for smaller embedded generators. Based on the SOF 2015 assessments, we see a greater and more immediate need for these changes. In the context of regional system stability, particularly within the Scottish network. It is essential that embedded generators have new settings to minimise the likelihood of cascaded loss of generation.

8.2.2
Low Frequency Demand Disconnection (LFDD)

The existing LFDD schemes provided by distribution companies have underlying demand assumptions in order to calculate the volume of demand disconnected at different stages of LFDD. As shown in Chapter 6, the increase in embedded generation behind the bulk supply points where LFDD relays are located will impact the level of demand disconnected at different times of the year.

In some locations a net generation loss may happen should LFDD relays operate. The SOF is therefore proposing a review of LFDD schemes by reviewing demand control requirements of the operational parts of the Grid Code. The objective of the review should be to achieve all year-round effective LFDD using different measures, some of which are described in the following section.

8.2.3
Generator Banding for Implementation of Requirement for Generators Code (RfG)

National Grid currently has limited visibility of embedded generators and their service capability. In addition to large power stations, we may require under Licence Exempt Embedded Medium Power Station agreements certain services to support operability such as operational metering, fault ride through and reactive power capabilities. In practice, we receive very limited information on stations below 50MW in England and Wales, 30MW in the Scottish Power TO area and 10MW in the SHETL TO area. Under the EU Code: Requirements for Generators (RfG) that is being implemented in Great Britain, generator requirements are banded across different MW categories from Band A to Band D. Band A relates to the smallest generation and Band D to those large power stations historically most capable and material upon system stability and operation. The definitions of the MW level for the banding between the 4 categories A, B, C and D are currently being assessed by a joint Grid Code and Distribution Code working group GC0048.

As we move forward, a greater proportion of generation will be in the lower MW banding categories. For embedded generation, the definitions of the MW banding thresholds between Bands A and B and between Bands B and C are important in respect of the technical capability that embedded generation would be mandated to provide to support system operability. For example, generation in the Type B category would be required to have operational metering and would be required to be capable of fault ride through. Generation in the Type C category would additionally be required to be capable of providing frequency response and more defined voltage support.

The adoption of lower MW banding thresholds will ensure that more embedded plant is robust and able to provide frequency and voltage control services in the future albeit at some increased capital costs to project developers. If embedded generation is capable of providing a range of ancillary services, this will help ensure such generation is able to support operability during minimum demand periods and help avoid it being curtailed. The balance between these technical requirements and costs is being reviewed by the GC0048 working group so that the most appropriate banding levels are set in GB.

8.2.4
Flexibility and Performance of New Generation Fleet

As discussed in the new technology section, the new generation fleet in coming years may have different designs and their performance against the future requirements of the grid should be assessed. Failing that and to compensate for varying degrees of non-compliance, larger volumes of response/reserve may have to be carried by the SO which increases the cost. The grid requirements identified as part of SOF should be used as the basis of assessing future generation fleets' capability and a more longterm cost-benefit analysis should be carried out should derogations against the future grid requirements be sought.

New Operability Services

8.3
New Operability Services

In previous chapters, an in depth review of the operability topics affected by the change in the energy landscape was presented. In each topic, should the existing tools and measures be insufficient, the emergence times of the operability challenges were identified. In addition, the individual mitigating measures and tools to address the system needs in the context of each topic were discussed. In the table below, a summary of the solutions which were identified as part of the assessment chapters is presented to identify the common solutions to address a number of system needs. This is intended to create a platform for further engagement with the stakeholders on the delivery of these services. Key actions are summarised in Table 10.

Table 10
New Operability Services

	RoCoF Management	Frequency Management	Voltage Management	Protection System Effectiveness	System Restoration Capability	Low Frequency Demand Disconnection	Commutation of HVDC links
Demand Side Services	Provision of fast response	Provision of fast response				New LFDD support	
Energy Storage	Provision of fast response	Provision of fast response	Voltage support (location dependent)		New black start provider	LFDD alternative	
Flexible Synchronous Generation	Increasing the system inertia	Increasing the system inertia	Provision of reactive response	Increasing fault infeed			Increasing fault infeed
Flexible Non-Synchronous Generation	Increasing the headroom	Increasing the headroom					
Interconnector Services	Provision of fast response	Provision of fast response	Provision of reactive response		New black start provider	LFDD alternative	
Synchronous Compensator	Increasing the system inertia	Increasing the system inertia	Provision of reactive response	Increasing fault infeed			Increasing fault infeed
Support from Embedded Generation		Provision of fast response	Provision of reactive response				
DSO Services		Utilising full dso capability	Utilising full DSO capability		New black start provider		
New Services from Non-Synchronous Generation	Provision of fast response	Provision of fast response	Enhanced reactive support		New black start provider		

8.3.1
New Services from Non-Synchronous Generation

Generation technologies such as solar PV and wind farms are capable of providing a wide range of system services envisaged in SOF. Many capabilities that are required for future grid operation have already been codified and the existing plants are capable to provide the service, should there be a commercial mechanism to access such capability. To enhance the operational tools, and to ensure future grid operability when the traditional response providers may not be present, it is essential that the full capability of non-synchronous generation technologies is utilised:

- RoCoF Management: The use of fast response capability of wind farms and solar PV in order to limit the rate of change of frequency (df/dt).
- Frequency Management: The use of power modulation capability of wind farms and solar PV in the form of fast response to contain the frequency when the inertia is low, which often coincides with times of high production (and therefore availability) of wind farms and solar PV plants.
- Voltage Management: Many wind farms connected to the transmission system already provide voltage support. The distributed connected wind farms and solar PV plants can also be used more effectively to manage local voltage issues.
- System Restoration Capability: To effectively re-energise wind farms connected to the system by AC links, the main system must be first energised. However, resuming the production from the wind farms is generally faster than thermal generation. In particular full converter wind turbines are less sensitive to grid disturbances which are observed during system restoration. The HVDC connected wind farms (offshore wind farms) expected in the future can initiate system restoration using the VSC converter capability.
- Low Frequency Demand Disconnection: As an alternative to disconnecting demand, the fast power response from wind and solar can be used to avoid severe frequency drops and act as an alternative to classic LFDD schemes.

New Operability Services

Key Actions

- Short Term Actions
  - – Ensure new ancillary services are developed to enable participation of non-synchronous generation in providing system services.
  - – Value the new system service to enable optimisation by service providers in decision making between revenue opportunities in non-energy production activities.
  - – Demonstrate the capability of wind farms and solar PV plants as part of the NIC-EFCC project in standalone and hybrid PV-Storage to support grid frequency.
- Supplementary Actions
  - – Work with wind turbine and solar PV inverter manufacturers to understand grid requirements, particularly those that are market driven, and the inherent capability of the non-synchronous generation technologies.
  - – Work closely with other TSOs in ongoing changes to ancillary services rules and markets to enable the participation of non-synchronous generation technologies in providing system services.

8.3.2
Demand Side Services

The existing demand side services are primarily for Short Term Operating Reserve and Static Frequency Response. Recently, Demand Side Balancing Reserve (DSBR) and Supplementary Balancing Reserve (SBR) have been introduced by National Grid for the purpose of managing tighter margins.

It is evident that the use of demand side services should expand, and in the context of SOF, be extended to a number of new areas.

- RoCoF Management: The use of demand side services in the form of fast response in order to limit the rate of change of frequency (df/dt).
- Frequency Management: Whilst demand side services are already utilised in this area, in the future as shown in Chapter 4, particularly in low demand conditions where the level of available synchronous response is limited, the demand side services should be explored for the purpose of both frequency control and providing additional flexibility to the grid.
- Low Frequency Demand Disconnection: This will potentially be a new service, from demand side participants where they can provide additional emergency measures to the grid as required.

Key Actions

- Short Term Actions
  – Engagement with demand side service providers and the industry to explore the possibility of provision of LFDD alternative services from demand side service providers.
  – Wider engagement with demand side service providers as part of SMART Frequency Control (NIC-EFCC) to ensure the new Enhanced Frequency Control Capability service specifications are consulted with potential new service providers.
- Supplementary Actions
  – With the rollout of smart meters, it is essential that suppliers are engaged in the ancillary services discussions and are fully aware of system needs to ensure the domestic demand side services are effectively utilised for future grid operation.
  – Further research into the control strategies which ensure coordinated access to demand side services by different parties.

8.3.3
Energy Storage

There are currently limited numbers of energy storage facilities in GB. Different forms of energy storage in the future may have significant potential to meet the needs of the grid. SOF 2015 has identified a number of new services for energy storage, subject to technology limitations:

- RoCoF Management: The use of fast energy charging/de-charging capability of certain energy storage technologies (i.e. battery storage) in the form of fast response in order to limit the rate of change of frequency (df/dt).
- Frequency Management: The use of both fast and slow energy charging/de-charging capability of certain energy storage technologies in various forms:
  – Fast response to contain the frequency when the inertia is low.
  – Slow response to provide continuous response and to provide flexibility (i.e. creating headroom) and to avoid curtailment of generation.
- Voltage Management: Energy storage, depending on connection points and sizes, can be used as reactive power compensation. The concentrations of energy storage needed to manage transmission system voltage are inevitably higher compared to the level which may be required to address distribution systems' needs.
- System Restoration Capability: The use of energy storage to provide block-loading support as well as energisation capability for the grid.
- Low Frequency Demand Disconnection: As an alternative to disconnecting the demand, the energy storage can be discharged to avoid severe frequency drop and act as an alternative to classic LFDD schemes.

New Operability Services

Key Actions

- Short Term Actions
  - Valuation of new services to form the basis of assessment for rollout of the service to energy storage.
  - Continue with trial of hybrid model renewable generation and energy storage to gather sufficient evidence on capability of the hybrid model, in addition to the data available from network led storage projects such as Low Carbon Network Fund storage demonstrations.
  - Address the regulatory barriers for ownership and provision of system services from energy storage by different parties.
- Supplementary Actions
  - Determine the most technically and economically viable model for roll out of the service (i.e. retrofitting existing generation sites with energy storage versus stand-alone energy storage installations only).
  - Demonstration of new services from energy storage, such as voltage support as well as research into new types of energy storage.

8.3.4 Flexible Synchronous Generation

The increase in non-synchronous generation may reduce the number of operating hours of some synchronous generation which is currently providing a number of ancillary services. Whilst the alternative services from new providers must be explored, the value of flexible synchronous generation should be factored in when deciding on future system services.

- RoCoF Management: The part loaded synchronous generation will increase the level of system inertia and will limit the rate of change of frequency (df/dt).
- Frequency Management: The additional inertia from part-loaded synchronous generation and the ramp up capability of such resources will help in frequency management, particularly if the availability of other services is limited.
- Voltage Management: The part loaded synchronous generation will provide natural fault infeed to the grid and increases the system strength. Such resource is also capable of providing voltage support subject to some technical limitations.
- Protection System Effectiveness: The fault infeed contribution from part loaded synchronous generation increases the system strength.
- Commutation of HVDC Links: The fault infeed contribution from part loaded synchronous generation increases the system strength and enables the full operation of HVDC Links (LCC type).

Key Actions

- Short Term Actions
  - Engage with existing power plant owners to develop better understanding of how flexible the existing fleet of synchronous generators are and the additional flexibility that can be achieved by modification of the plant in terms of:
    - The minimum output level that the synchronous generators can run and the services they can provide at that level.
    - The ramp up and down capability at different output levels.
  - Engage with the developers and manufacturers of new fleets of synchronous generation in GB to ensure the flexibility requirements and future services are understood and factored in the design of the new fleets.
  - Value the services that flexible synchronous generation fleets can provide and use as the basis for cost benefit analysis in specification of new system services.
- Supplementary Actions
  - Further research into new flexible synchronous generation technologies from both technical and commercial perspectives.

8.3.5 Flexible Non-Synchronous Generation

Wind and Solar PV power plants, whilst intermittent, have many capabilities in terms of providing flexibility to the grid, which in conjunction with other services will help in enhancing the future operational tools. The de-loading capability instead of curtailment and the headroom in the energy market created by such resources (especially when needed for a short period of time) can help in some aspects of future grid operation.

- RoCoF Management: There are a number of scattered hours that a given generation background may give rise to the rate of change of frequency. The utilisation of short-term de-loading of non-synchronous generation assists by increasing the headroom in the energy mix for synchronous generation and increases the system inertia. This can form part of a new service for wind farms and solar PV plants for managing RoCoF.
- Frequency Management: Similar to above, and in addition to the extra inertia provided for the short term, the flexible non-synchronous generation can be used in provision of frequency response.

Key Actions

- Short Term Actions
  - Engage with existing wind farm and solar PV power plant owners to explore the technical and commercial aspects of utilisation of short-term flexibility of non-synchronous generation resources.
  - Develop an agreed framework to utilise this capability from a wider volume of non-synchronous generators, including those which are not directly connected to the transmission system. The potential role of generator aggregators should be explored.
- Supplementary Actions
  - Perform demonstration of the use of such resources as part of a potential future trial.

New Operability Services

8.3.6
Interconnector Services

The HVDC interconnectors between GB and other power systems are currently used to a limited scale in provision of ancillary services. The technology used in the HVDC converter (whether it is CSC or VSC based) plays a major role in the capability of the interconnector to provide different services. With the increasing number of interconnectors, it is expected that the number of hours the individual interconnectors are fully loaded will decrease (given the whole-sale price difference is minimised) and therefore this will create a good opportunity to utilise the interconnectors' capability for system services. Many of the services envisaged below are dependent on the capability of the other power system and are subject to impact assessment / agreement from other TSOs.

- RoCoF Management: The fast power response capability of HVDC interconnectors and in particular VSC based links can be used as RoCoF alternative services on the system.
- Frequency Management: Similar to above, the utilisation of interconnectors for this service allows better use of the flexibility resources in different synchronous areas for the purpose of frequency management.
- Voltage Management: The VSC based HVDC interconnectors have independent control of active and reactive power and therefore at import / export and float conditions are capable of providing support to the grid for the purpose of voltage management.
- System Restoration Capability: The use of interconnectors to provide block-loading support, as well as energisation capability for the grid.
- Low Frequency Demand Disconnection: As an alternative to disconnecting demand, the interconnector can be instructed to change the power export / import as an emergency measure to avoid severe frequency drop and act as an alternative to classic LFDD schemes.

Key Actions

- Short Term Actions
  - Via engagement with interconnector developers and owners, as well as other TSOs, develop a shared understanding of system services required in GB and other neighbouring countries where there is interconnection between or planned for the future. This will facilitate the commercial discussions in procuring the services from interconnectors and what trade-offs across interconnectors between GB and other neighbouring countries can take place.
- Supplementary Actions
  - Through engagement with Ofgem and developers enhance the methodology for valuation of system services used as part of interconnector regulated revenue assessment (Cap and Floor).
  - Carry out cross-TSO commercial developments and resource optimisation to enhance the operability tools and availability of the services on interconnectors.

8.3.7
Synchronous Compensator

A synchronous compensator will have the characteristics of a synchronous generator but without the need to operate at minimum active power output. The services envisaged are similar to the services mentioned earlier for flexible synchronous generators (as the capability of operating in synchronous compensator mode for future fleets determines the degree of flexibility which can be achieved). However, the importance of synchronous compensator services for the GB power system is mainly in the context of the closure of existing power stations and the possibility of the retention of those plants to operate as synchronous compensators. The increase in non-synchronous generation may reduce the number of operating hours of some synchronous generation which are currently providing a number of ancillary services. Whilst the alternative services from new providers must be explored, the value of flexible synchronous generation should be factored in when deciding on future system services.

- RoCoF Management: A synchronous compensator will increase the level of system inertia (although the amount of inertia which is contributed is less than when operating at part load) and will limit the rate of change of frequency (df/dt).
- Frequency Management: The additional inertia from a synchronous compensator may help in frequency management. In addition, certain areas of the network will benefit from a synchronous compensator to ensure the stability of the grid.
- Voltage Management: The synchronous compensator will provide natural fault infeed to the grid and increases the system strength. Such resource may also be capable of providing limited voltage support subject to some technical limitations.
- Protection System Effectiveness: The fault infeed contribution from a synchronous compensator increases the system strength.
- Commutation of HVDC Links: The fault infeed contribution from a synchronous compensator increases the system strength and enables the full operation of HVDC Links (LCC type).

Key Actions

- Short Term Actions
  - Engage with existing power plant owners to explore the possibility of strategic conversion of their generation fleets to synchronous compensators.
  - Value the services that a synchronous compensator fleet could provide and use as the basis for cost benefit analysis in specification of new system services.
- Supplementary Actions
  - Engage with the manufacturers and developers in better communicating the importance of having such capabilities, in addition to new services.

New Operability Services

8.3.8
Support from Embedded Generation

As shown in Chapters 5 and 6 relating to system strength, voltage support and the impact of embedded generation on system stability, there is a growing need for additional voltage support for the system. The existing embedded generators provide very little dynamic voltage support (in very exceptional cases) whilst many of them have capability to do so. In addition, as the analysis has shown, the future distribution networks may require more dynamic voltage support with the reduction of system short circuit levels. Similarly, the ability to regulate active power by embedded generation exists but is not utilised in many cases.

- Frequency Management: Given the large volume of embedded generation connections, spread across the whole system, it provides a great opportunity for frequency management services as standalone or when combined with energy storage.
- Voltage Management: The regional need for voltage management, in particular at the distribution network level, may be more efficiently met by embedded generation.

Key Actions

- Short Term Actions
  – Work with DNOs to agree the frameworks to access the services from embedded generation, to ensure the whole-system impact of such actions are fully understood.
  – Demonstrate the capability of embedded generation as part of NIC-EFCC project in standalone and with the use of Battery Storage to support grid frequency.
  – Develop new commercial services to enable the participation of embedded generation in grid frequency control.
  – Develop modelling techniques to accurately determine the system impacts of embedded generation providing voltage support and the effectiveness of such services for both TOs and DNOs.
- Supplementary Actions
  – Initiate joint TSO / DNO trials on accessing the system services from embedded generation to determine the level of resource optimisations possible when embedded generators are actively participating in providing system services.

8.3.9
Distribution System Operator (DSO) Services

When the active control capability within the distribution networks exists to manage the network assets, and demand and generation in real time in a more dynamic way, it allows provision of different system services from the distributed resources. Such coordination and active network management could be done via a DSO, and therefore the DSO will have additional capability to act as a system service provider for wider network needs. A number of system services highlighted in the SOF can then be provided by the DSO. At a high level, the benefits of having active DSOs from the provision of system services include:

- Ability to forecast the demand and generation within the DSO's boundary of operation more accurately, and to determine the degree of support that provided at different interface points (i.e. Grid Supply Points).
- Flexibility of the DSO to provide the service using the DNO assets or via contracting network users (i.e. embedded generation and demand).
- Avoiding the potential conflict of services (between those needed by the DNO and those intended for wider system needs) and enabling whole-system thinking in the provision of system services.

Whilst the capability of DSOs in the provision of system services is being determined as part of Smart Grid Forum Workstream 7 (Distribution System 2030 Project), following the earlier engagement with DNOs we envisage the following services to be able to be provided by the DSO:

- Frequency Management: The DSO can utilise a wider range of resources as shown in number of trials such as CLASS (led by ENWL), or Customer Led Network Revolution (CLNR), Project FALCON, or Smarter Network Storage to deliver frequency response service.
- Voltage Management: The DSO can utilise a wider range of resources, including the DNO assets, to enhance the voltage control of the system thorough a variety of means including operation of embedded customer services or operation of DNO owned assets. This service may include the ability to actively control the reactive power exchange at GSPs.
- System Restoration Capability: The DSO can play a major role in future system restoration and enhancing the security of supply. The ability to coordinate the reconnection of embedded generation will be an extremely favourable option to reduce the time it takes to fully restore the demand.

In a wider context, the DSO's capability to offer system services is likely to also provide the ability to utilise Demand Side Response services (via load and generation management) through contractual arrangements to alleviate network congestion.

Key Actions

- Short Term Actions
  - Work with DNOs to agree the frameworks to access the services from a wide range of distributed resources such as embedded generation, storage and demand.
  - Develop common customer propositions for DSO services.
  - Identify the best value options for the consumer (considering the DSO option as one route in conjunction with other options).
  - Develop new commercial services to enable new entrants to offer various system services, and explore the wider system considerations of providing these services from DSO type services (i.e. voltage reduction for demand control and offer service).
  - Develop modelling techniques to accurately model the whole-system behaviour of DSOs.
  - Agree the framework to underpin the new roles and responsibilities and identify technical and commercial code changes to enable the provision, and procurement of DSO services.
- Supplementary Actions
  - Initiate joint TSO / DNO trials on accessing the system services from pseudo-DSOs to determine the level of resource optimisations possible. In doing so, a full review of already trialled and demonstrated projects as part of Innovation Funding Incentive (IFI), Low Carbon Network Fund (LCNF), Network Innovation Allowance (NIA) and Network Innovation Competition (NIC) should be undertaken so the trial provides sufficient knowledge to enable the provision of DSO system services.
  - Deliver the required changes identified to various codes and frameworks, once the whole-system impacts and benefits are known.

New Operability Services

Table 11
Future Operability Services and Actions

	Short Term Actions	Supplementary Actions
New Services From Non-Synchronous Generation	■ Develop new ancillary services to utilise non-synchronous generation. ■ Value the services to indicate revenue opportunities for non-energy production activities. ■ Demonstrate the capability of wind and solar PV (standalone and hybrid PV-Storage) to support frequency.	■ Review grid requirements and the inherent capability of non-synchronous generation technologies with manufacturers. ■ Review changes that other TSOs, have made to ancillary services to enable the participation of non-synchronous generation.
Demand Side Services	■ Engage with demand side service providers on LFDD alternatives. ■ Engage widely through the SMART Frequency Control project on the new Enhanced Frequency Control Capability service specifications.	■ Ensure the effective use of domestic demand side services by engaging suppliers in service discussions. ■ Further research strategies to coordinate access by different parties to demand side services.
Energy Storage	■ Valuation of new services. ■ Continue to trial hybrid renewable generation and storage model. ■ Address regulatory barriers for ownership and provision of system services from energy storage.	■ Determine the most viable model for the service (i.e. retrofitting existing generation with storage versus stand-alone storage installations). ■ Demonstrate new services such as voltage support as well as research into new types of energy storage.
Flexible Synchronous Generation	■ Engage with plant owners to better understand any additional flexibility through plant modification in terms of: – Minimum output level and services at that level; – Ramp up and down capability at different output levels. ■ Work with manufacturers and developers to factor flexibility and new services into new plant design. ■ Value the services that flexible generation can provide.	■ Further research into new flexible synchronous generation technologies from both technical and commercial perspectives.
Flexible Non-Synchronous Generation	■ Engage with wind farm and solar PV plant owners on the technical and commercial aspects of utilising short-term resource flexibility. ■ Develop framework to more widely utilise this capability. (The role of aggregators should be explored.)	■ Trial the use of such resources.

	Short Term Actions	Supplementary Actions
Interconnector Services	■ Engage with developers, owners and other TSOs to develop a shared understanding of the system services required in GB and other countries. This will facilitate trade-offs between countries.	■ Enhance the methodology to value services in regulated revenue assessments (Cap and Floor). ■ Cross-TSO resource optimisation to enhance operability tools and services.
Synchronous Compensator	■ Explore the conversion of existing generators to synchronous compensators with plant owners. ■ Value services that synchronous compensators could provide as a basis for new system services.	■ Engage with manufacturers and developers on the importance of having such capabilities.
Support From Embedded Generation	■ Work with DNOs on frameworks to access services. ■ Demonstrate capability as part of the SMART Frequency Control project to support grid frequency. ■ Develop new services to enable participation in frequency control. ■ Model the system impacts of embedded generation in providing voltage support and the effectiveness for TOs and DNOs.	■ Initiate joint TSO / DNO trials on accessing system services from embedded generation to determine the level of resource optimisation possible when these generators are actively participating in providing system services.
DSO Services	■ Work with DNOs on frameworks to access services from a range of distributed resources including generation, storage and demand. ■ Develop common customer propositions for DSO services. ■ Identify the best value options for consumers (considering DSO's in conjunction with other options). ■ Develop approaches to enable new entrants to offer various system services. Explore the wider system considerations of providing these as DSO type services (i.e. voltage reduction for demand control). ■ Develop techniques to model the whole-system behaviour of DSOs. ■ Framework and code changes to underpin new roles and enable the provision of DSO services.	■ Initiate joint TSO / DNO trials on accessing the system services from pseudo-DSOs to determine the level of resource optimisation possible. In doing so, review projects already trialled and demonstrated through innovation funding. ■ Deliver the required changes identified to various codes and frameworks, once the whole-system impacts and benefits are known.

Chapter 9
Conclusions and the Way Forward

Conclusions and the Way Forward

The transition to a low carbon economy characterises a power system which is dependent on enhanced capabilities from new technology solutions, a coordinated approach to utilisation of whole system resources and evolving requirements for increased flexibility. System operability will continue to become an area of increasing focus in future years however opportunities for technology innovation and the provision of new services with appropriate commercial frameworks are areas of growth for the development of suitable mitigations.

The technology and commercial environments of power systems operation will continue to evolve throughout the twenty year assessment period of SOF 2015. One key purpose of the SOF is to identify what services and capabilities are required and how best they can be provided. The continual improvement process for SOF development therefore takes a wide-reaching and holistic approach which aims to enhance assessments every year to reflect the latest innovations, capabilities and service opportunities informed by your feedback.

In the development of SOF 2015 we have received an overwhelmingly positive response from our stakeholders to enhance the framework and we have acted on your feedback to introduce new topics, engage with you throughout the assessment process and present our future operability strategy. Comprehensive and transparent engagement with the industry remains a core principle of SOF moving forwards and gives us confidence that the right strategic investment and service solutions will continue to be identified and developed in line with system requirements and stakeholder needs. SOF 2016 will continue to be a platform for collaborative industry working which provides a route to commercial appraisal for solutions which ensure the future operability of GB power networks.

To provide your views, please write to us at **box.transmission.sof@nationalgrid.com**. We also actively encourage you to complete the feedback form on the SOF website **http://www.nationalgrid.com/sof**

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Glossary

Acronym	Word	Description
	Ancillary Services	Services procured by a system operator to balance demand and supply and to ensure the security and quality of electricity supply across the transmission system. These services include reserve, frequency control and voltage control. In GB these are known as balancing services and each service has different parameters that a provider must meet.
CCS	Carbon Capture and Storage	Carbon (CO2) Capture and Storage (CCS) is a process by which the CO2 produced in the combustion of fossil fuels is captured, transported to a storage location and isolated from the atmosphere. Capture of CO2 can be applied to large emission sources like power plants used for electricity generation and industrial processes. The CO_2 is then compressed and transported for long term storage in geological formations or for use in industrial processes.
CCGT	Combined Cycle Gas Turbine	Gas turbine that uses the combustion of natural gas or diesel to drive a gas turbine generator to generate electricity. The residual heat from this process is used to produce steam in a heat recovery boiler which in turn, drives a steam turbine generator to generate more electricity.
CHP	Combined Heat and Power	A system whereby both heat and electricity are generated simultaneously as part of one process. Covers a range of technologies that achieve this.
CP	Consumer Power	A Future Energy Scenario outlined in FES 2015.
DSR	Demand Side Response	A deliberate change to an industrial and commercial user's natural pattern of metered electricity or gas consumption, brought about by a signal from another party.
DECC	Department of Energy and Climate Change	A UK government department: The Department of Energy & Climate Change (DECC) works to make sure the UK has secure, clean, affordable energy supplies and promote international action to mitigate climate change.
DNO	Distribution Network Operator	Distribution network operators own and operate the electricity distribution networks. In the England and Wales network, the 132kV networks and below are operated by DNOs and in the Scottish Network, below 33kV is classed as distribution.
EFCC	Enhanced Frequency Control Capability	The 2014 Network Innovation Competition (NIC) project awarded by Ofgem to National Grid and demonstrates the provision of enhanced frequency services from a wide range of resources.
EV	Electric Vehicle	An electric vehicle has an electric motor to drive the vehicle. It can either be driven solely off a battery, as part of a hybrid system or have a generator that can recharge the battery but does not drive the wheels. We only consider EVs that can be plugged in to charge in this report.
ETYS	Electricity Ten Year Statement	The ETYS illustrates the potential future development of the National Electricity Transmission System (NETS) over a ten year (minimum) period and is published on an annual basis.
EG	Embedded Generation	Power generating stations/units that don't have a contractual agreement with the National Electricity Transmission System Operator (NETSO). They reduce electricity demand on the National Electricity Transmission System.
ENA	Energy Networks Association	The Energy Networks Association is an industry association funded by gas or transmission and distribution licence holders.
ENTSO-E	European Network of Transmission System Operators – Electricity	ENTSO-E is an association of European electricity TSOs. ENTSO-E was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising electricity markets in the EU.
EU	European Union	A political and economic union of 28 member states that are located primarily in Europe.
FES	Future Energy Scenarios	The FES is an annual publication by National Grid which illustrates the changes in the energy landscape under different scenarios
FFR	Firm Frequency Response	Firm Frequency Response (FFR) is the firm provision of Dynamic or Non-Dynamic Response to changes in Frequency. http://www2.nationalgrid.com/uk/services/balancing-services/frequency-response/firm-frequency-response/
GG	Gone Green	A Future Energy Scenario outlined in FES 2015.

Acronym	Word	Description
GTYS	Gas Ten Year Statement	The GTYS illustrates the potential future development of the (gas) National Transmission System (NTS) over a ten year period and is published on an annual basis.
GW	Gigawatt	1,000,000,000 watts, a measure of power
GB	Great Britain	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
HVDC	High Voltage Direct Current	A type of power transmission technology which used Direct Current (DC) instead of Alternating Current (AC). The benefit of HVDC technology is generally reduced losses (and cost) for long distance power transfer and is the preferred technology when connecting two different power systems with different frequencies. When HVDC links connect two power systems together, the inertia of the systems cannot be shared.
ITPR	Integrated Transmission Planning and Regulation	Ofgem's Integrated Transmission Planning and Regulation (ITPR) project examined the arrangements for planning and delivering the onshore, offshore and cross-border electricity transmission networks. Ofgem published the final conclusions in March 2015.
LCC	Line Commutated Converter	The technology used in classical High Voltage Direct Current converter technology (part of the family of Current Source Converter Technology)
LFDD	Low Frequency Demand Disconnection	An emergency measure triggered when the system frequency goes beyond operational limits to curtail demand in order to keep the system stable.
LOLE	Loss of Load Expectation	LOLE is used to describe electricity security of supply. It is an approach based on probability and is measured in hours/year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. This does not mean there will be loss of supply for X hours/year. It gives an indication of the amount of time, across the whole winter, which the system operator (SO) will need to call on balancing tools such as voltage reduction, maximum generation or emergency assistance from interconnectors. In most cases, loss of load would be managed without significant impact on end consumers.
LCNF	Low Carbon Network Fund	A fund established by Ofgem to support projects sponsored by the distribution network operators (DNOs) to try out new technology, operating and commercial arrangements.
MVA	Mega-Volt-Amp	The apparent power
MVar	Mega-Volt-Amp-Reactive	The imaginary part of the apparent power – This affects the system voltage
MW	Megawatt	1,000,000 Watts, a measure of power.
	Merit Order	An ordered list of generators, sorted by the marginal cost of generation.
MG	Micro Generation	Defined within this document as generation units with an installed capacity of less than 1MW.
NETS	National Electricity Transmission System	It transmits high-voltage electricity from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single system operator (SO).
NP	No Progression	A Future Energy Scenario outlined in FES 2015.
NSG	Non-Synchronous Generation	The generation technologies which are de-coupled from the grid, and do not contribute to the system inertia. Example; Wind Turbines, Solar PV, and HVDC Converter.
OFGEM	Office of Gas and Electricity Markets	The UK's independent National Regulatory Authority, a non-ministerial government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers.
PMU	Phasor Measurement Unit	A monitoring device which can provide measurement with greater resolution, and they can be synchronised using GPS clock to offer detailed visibility of how the system respond to changes and faults.
PV	Photovoltaic	A method of converting solar energy into direct current electricity using semi-conducting materials.

Glossary

Acronym	Word	Description
	Pumping Demand	The power required by hydro-electric units to pump water into the reservoirs.
	Smart Meter	New generation gas and electricity meters which have the ability to broadcast secure usage information to customers and energy suppliers, potentially facilitating energy efficiency savings and more accurate bills.
	Summer Minimum	The minimum power demand off the transmission network in any one fiscal year: Minimum demand typically occurs at around 06:00am on a Sunday between May and September.
	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. Low system inertia increases the risk of rapid system changes.
	System Operability	The ability to maintain system stability, asset ratings and operational parameters within pre-defined limits safely, economically and sustainably.
RoCoF	Rate of Change of Frequency	A type of relay used to detect loss of mains and disconnect the generation. This type of relay used the deviations in the frequency as a trigger and therefore is sensitive to the rate of change (df/dt).
SO	System Operator	An entity entrusted with transporting energy in the form of natural gas or power on a regional or national level, using fixed infrastructure. Unlike a TSO, the SO may not necessarily own the assets concerned. For example, National Grid operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power.
SP	Slow Progression	A Future Energy Scenario outlined in FES 2015.
SQSS	Security and Quality of Supply Standard	The standard which sets out the design and operation criteria of the onshore and offshore transmission networks.
	Transmission Losses	Power losses that are caused by the electrical resistance of the transmission system.
TSO	Transmission System Operators	An entity entrusted with transporting energy in the form of natural gas or power on a regional or national level, using fixed infrastructure.
UK	United Kingdom	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.

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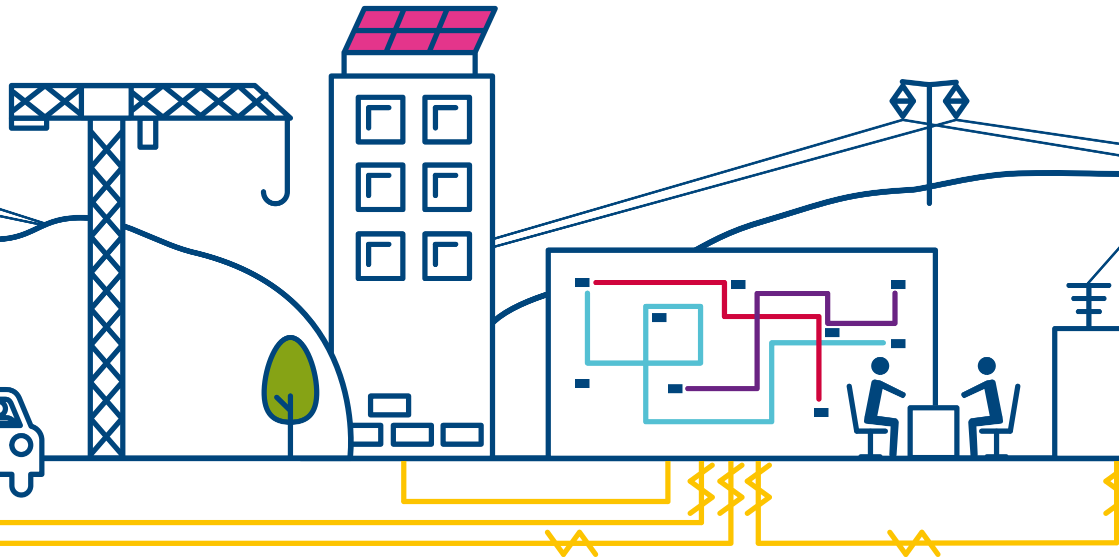

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