# Operability Strategy Report

December 2022

ESO

# Navigation

To help you find the information you need quickly and easily we have published the report as an interactive document.

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## Page navigation explained

Back a page

Forward a page

Return to contents

From here you can navigate to any part of the publication

## Buttons

Button

Access additional information by hovering on the rectangular buttons positioned beneath many of our charts

## Expand content

Rollover or click the plus symbol to expand or enlarge content

## More information

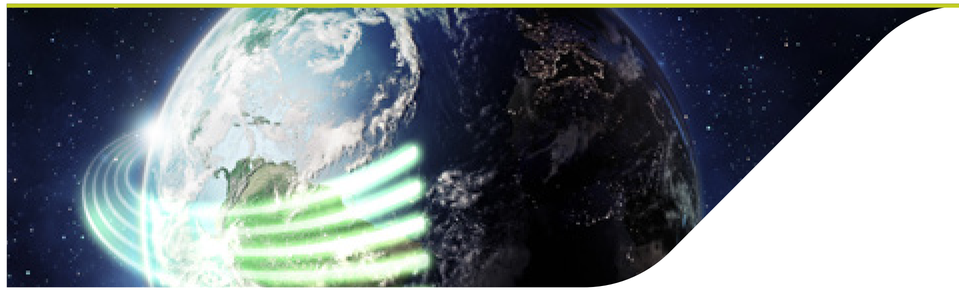
Rollover or click the info symbol for more information

## Text Links

Click highlighted orange text to navigate to an external link. Or to jump to another section of the document

# Contents





# Decarbonisation

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# Decarbonisation

## What do we mean by decarbonisation?

Decarbonising the electricity power system in GB is critical to meeting the governments ambitions on the way to net zero. A sustainable energy system is something we are committed to enabling through all of our work. As the ESO, in our role of powering Britain, we want to ensure that we are ready to decarbonise the power system and this poses some challenges which, with industry, we intend to overcome. Here we explain what we mean by decarbonisation of the electricity system. We have then used these terms throughout the report.

Decarbonisation of the electricity system is leading to changes in four key areas:

- Less dispatchable generation
- More asynchronous generation
- More variable sources of generation
- Generation moving to different areas

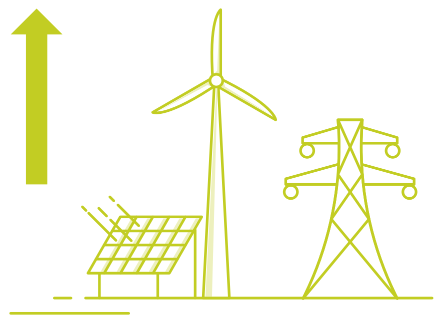
Less dispatchable generation refers to the closure of traditional synchronous generators like coal and gas. These provided firm, flexible power and system services like voltage and stability. They were also typically used for restoration services.

More asynchronous generation refers to the increase in generators connected by inverter-based technologies, such as wind, solar and battery storage. These types of generators are less flexible than traditional synchronous generators and generally do not provide system services.

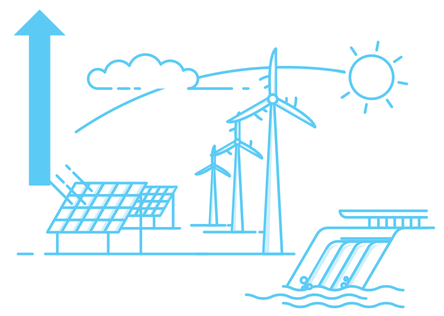
More variable sources of generation refers to the increase in generators which are more dependent on an input to generate, like sunshine or wind, and are more prone to variability in energy output due to input variability.

Generation moving to different areas refers to new generation locating at network extremities and further away from demand centres such as offshore, in Scotland and in South West England. It also refers to the increase in generation on the distribution networks.

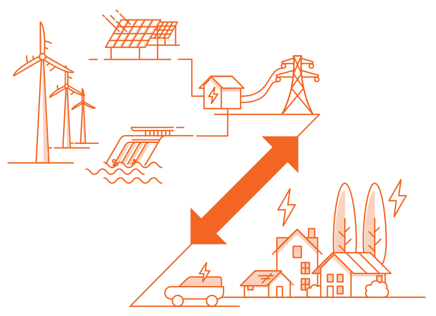
Less dispatchable generation



More asynchronous generation



More variable sources of generation



Generation moving to different areas

Operability Strategy Report / Decarbonisation / 05

# ESO Publications

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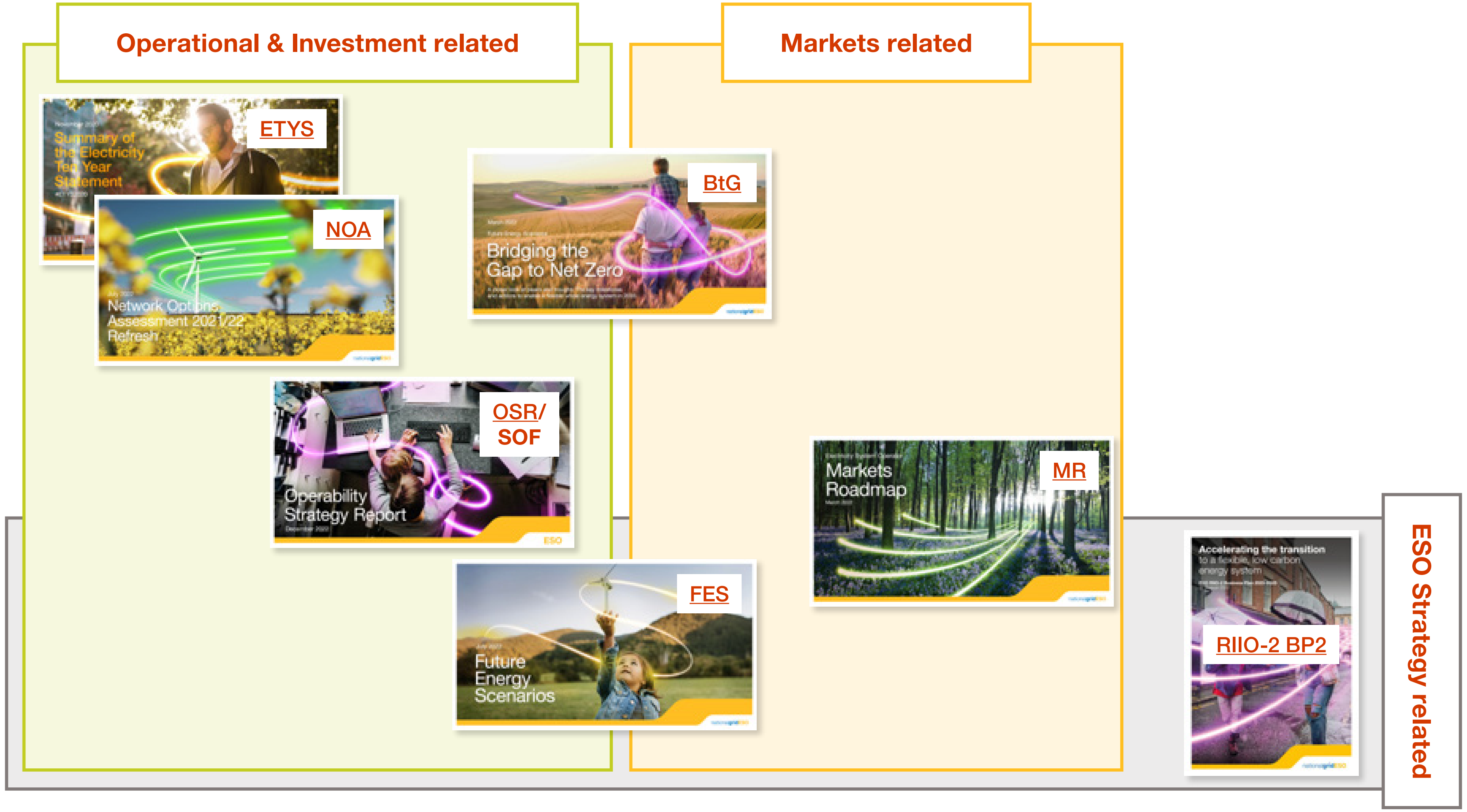
# ESO Publications

## Markets Roadmap

Our ambition is to design market arrangements that facilitate security of supply at the lowest sustainable cost for customers, while enabling the transition to net zero. Our annual Markets Roadmap sets out our development and design principles for how we will shape future market arrangements. We focus on the future trends and investigate the interactions between ESO and wider industry markets.

## Bridging the Gap to Net Zero

We look at the key messages from our Future Energy Scenarios to understand what needs to be done to bridge the gap between today and 2050.





Operability Strategy Report / ESO Publications / 07

# Executive Summary

ESO

# Executive Summary

**Our annual Operability Strategy Report explains the challenges we face in operating a rapidly changing electricity system and describes what capabilities we need to resolve these challenges and enable a zero carbon electricity system in 2035.**

We continue to work closely with our stakeholders to look across systems, markets, policy, technology and innovation as we develop and deliver solutions in response to these challenges. Collaboration and co-creation are at the heart of everything we do and throughout this report, we signpost where to look for more information. The 'how to get involved' section of this report also highlights opportunities for industry engagement as we continue to tackle the future challenges in an ever-changing system.

As with previous reports, there is a close interaction between the Markets Roadmap and the Operability Strategy Report. These two documents complement one another with the Operability Strategy Report defining our operational requirements and future system needs, while the Markets Roadmap explains how our markets are evolving to meet these future needs in the most efficient way.

Operability Strategy Report / Executive Summary / 09

# Executive Summary

## Context

Decarbonisation, decentralisation and digitalisation are driving significant change across the electricity network, impacting how we operate the system now and into the future. These challenges are set against a backdrop of significant other industry change such as the Distribution Network Owner to Distribution System Operator transition and the growth of Distributed Energy Resources (DER) and interconnection. It is our role to support the energy transition, while making sure we can continue to operate the system in a way that delivers the biggest benefits to consumers.

Across the workstreams in this report we have delivered, and are delivering, innovative systems, products and services. These will transform how we operate Great Britain's electricity system, and mean we are ready to operate a zero carbon network in 2025. But it doesn't stop there, the system will continue to evolve as we strive towards net zero. This means a fundamental change in how our system is operated – integrating newer technologies right across the system – from large scale off-shore wind, to domestic scale solar panels, to increased demand side participation. We recognise the critical nature of our work – to ensure safety and reliability, to lower consumer bills, reduce environmental damage and increase overall societal benefits and we are committed to collaborating with industry to unlock this value.

Operability Strategy Report / Executive Summary / 10

## Report structure and key messages

Previous editions of this report have considered the operability challenges in 5 security workstreams: Frequency, Stability, Voltage, Restoration and Thermal. This year we have added two more: Within-day Flexibility and Adequacy. These new sections reflect the changing nature of the future system challenges we face.

Across these seven workstreams we explain the future operability challenges, the capabilities and requirements we need, as well as the next big operational challenges on the horizon. For faster reading, a summary of our key messages in each chapter is provided here.

To aid the reader, we have restructured the report and grouped the challenges into two themes:

### 1. Reliable network

This section focuses on system requirements that are locational by nature. These are Stability, Thermal, Voltage and Restoration. For each of these challenges, we resolve the requirement based on the physical needs of the power system and represent the sole customer of such services.

### 2. Balancing the system

This section focuses on the system energy balance. These are Frequency, Within-day Flexibility and Adequacy. All of these areas ensure energy balance but over different timescales. They are national in scope and do not currently have a locational component. Within this area, both the market and the Electricity System Operator (ESO) have incentives to resolving the challenges.


Operability Strategy Report / Executive Summary / 11

# Reliable Network Summary

## Stability

Stability has traditionally been supplied as an inherent by-product of synchronous generation. More asynchronous generation continues to drive a decline in this inherent stability of the system, with a gradual reduction in system inertia. We currently meet any requirement (after market dispatch) by synchronising gas and biomass generators. This has both an economic and carbon impact so we need to find and procure alternative sources of stability to support our net zero ambition.

By 2025 the minimum inertia that we can operate at will be 102GVAs. This assumes we need to secure against a largest loss of 1800MW and keeping the Rate of Change of Frequency (RoCoF) within 0.5Hz/s. We currently operate at a minimum of 140GVAs and so are starting the process to reduce our operational limits to meet our zero carbon targets. This will be achieved through the Frequency Risk and Control Report (FRCR) – reducing minimum inertia is the focus of the 2023 report. Operationally we could meet our requirement to maintain system inertia at 102GVAs based on the current system conditions (mainly by synchronising plant), however we acknowledge that this is not the most economic, nor efficient approach. Future procurement of stability services will be to reduce operational costs, rather than for system security reasons.

In addition to declining inertia, we are also starting to observe challenges with low short circuit levels as less dispatchable generation is replaced by more asynchronous generation.

We are currently reviewing our policy for managing low short circuit levels. We are working closely with industry and international Transmission System Operators (TSO's) to understand the different options for measuring and maintaining system strength, including defining the different obligations industry parties should aim to maintain. At present, our studies suggest that we have sufficient short circuit level on the system until 2029 and we are working on solutions for optimal procurement of this service for future years. Any future procurement will take learnings from the ongoing policy work to understand and agree the best approach for calculating and managing low short circuit levels.

We are also working towards enhancing the use of Electro Magnetic Transient (EMT) studies to provide detailed system studies. This will further support our ability to manage the emerging operability system stability challenges.

Grid forming technology will be a significant, contributing factor to future stability of the system. This enables inverter-based technology to provide similar characteristics to traditional synchronous generation. This will be key to effectively managing a net zero power system. Whilst the non-mandatory Grid Code specification provides guidance on minimum requirements for enhancing asynchronous plant, we anticipate that future market arrangements will form the basis of where grid forming technology could be procured by the ESO.


Operability Strategy Report / Executive Summary / 12

# Reliable Network Summary

### Voltage

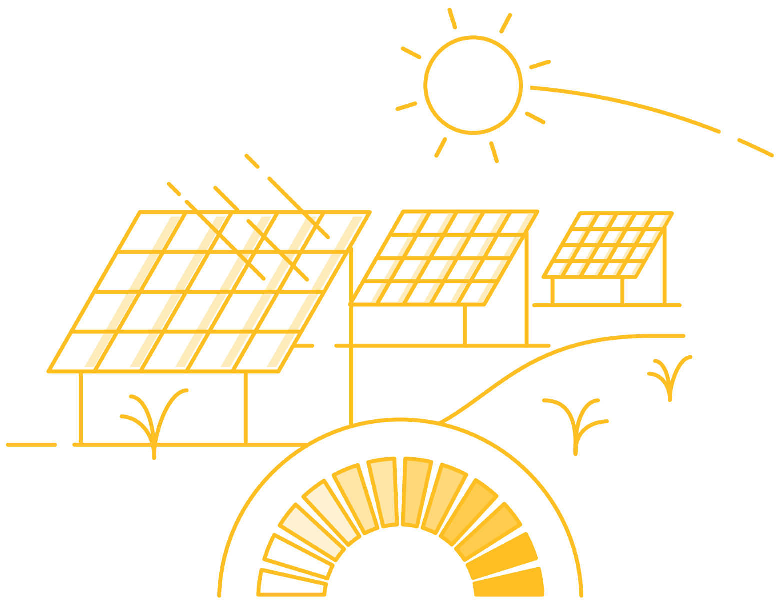
Voltage is influenced by, and managed through, the injection and absorption of reactive power. We must maintain voltage levels across the transmission network within the Security and Quality of Supply Standards to ensure safety and reliability of the network. Voltage management continues to be challenging as reactive power demand on distribution networks continues to decrease and power flows across the transmission network reduce. These system changes are driving an increasing need to absorb reactive power on the transmission system. Less dispatchable generation is reducing available reactive power capacity in the right regions. In many regions, we are synchronising generation out of merit to access their reactive power capacity. This increases balancing costs.

Our voltage screening report 2022 has again highlighted numerous areas where reactive capacity is reducing or voltage management costs are increasing. There is a need in both the short and medium term to increase available reactive capacity in the right locations and reduce consumer costs.

Reactive utilisation costs increased by nearly 200% in 2021/22 compared to 2020/21. This was mostly driven by the impact of wholesale gas prices on the default price paid to reactive power providers, but reactive utilisation still increased by 20%.

In addition, more reactive power capacity is needed to meet requirements in 2025 and beyond, otherwise this could increase operational costs significantly as we synchronise generation for voltage support. This would also negatively impact our ability to meet our zero carbon operation in 2025 ambition. We have worked with National Grid Electricity Transmission to further refine the reactive needs for England and Wales in 2025 and are exploring options to deliver the best value for the consumer. We are now assessing requirements beyond 2025 and will provide an update to industry in mid-late 2023.

Looking forward the message within our voltage screening reports and system studies is clear. We need to reduce our reliance on fossil fuel generators and increase access to more reactive capability in the right locations. We will need to manage high volts during low demand without removing more network assets, secure the system for faults causing low volts during peak demand, and mitigate more dynamic voltage levels during interconnector flow changes.




Operability Strategy Report / Executive Summary / 13

# Reliable Network Summary

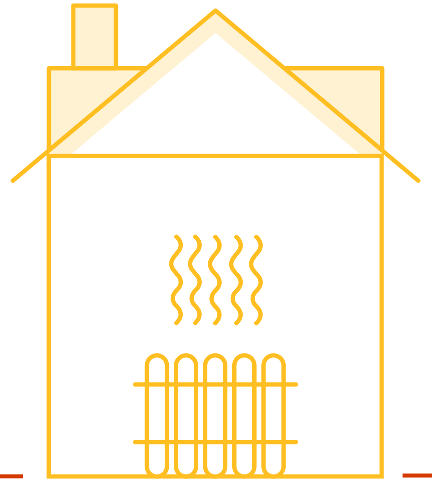
## Thermal

We manage the flow of electricity across the high voltage transmission system from where it is generated to where it is consumed. The transmission network has a limited capacity to transport this energy. We must manage the power flows to prevent network assets becoming overloaded and loss of supply to areas of the network. We are at the forefront of planning a network fit for the future through the Electricity Ten Year Statement and Network Options Assessment. Where the network does not have enough capacity, we mostly manage network constraints by constraining generation. We are mindful of the impact these actions have from both a carbon and cost perspective and are proactively focused on seeking innovative solutions to manage these constraints. We are developing further commercial intertrip schemes and have worked with the TOs to deliver innovative ways of increasing constraint boundaries on the existing network. We are also working with Ofgem to accelerate delivery of strategic network investment ahead of 2030.

Our ambition is to operate a zero carbon network in 2035 and enable net zero by 2050. This requires significant investment in the transmission network to transfer power from renewable generation to new and changing sources of demand. In July 2022 we published our first Holistic Network Design (HND) alongside a refreshed Network Options Assessment. Together they recommend 94 asset investments to deliver a network which can accommodate the Government's ambition of 50GW offshore wind by 2030.

The Future Energy Scenarios (FES) indicate the need for a demand side strategy to avoid wasting renewable energy. We need to incentivise new demand to connect where there is excess generation. This can help effectively alleviate constraint costs. To achieve this goal, we are working on two innovation projects to demonstrate how green hydrogen can support constraint management and develop a probabilistic model which quantifies the risk of energy flow congestion. FES also indicates that we will be a net exporter of electricity by 2030. With much of our interconnection being in the South East, we will need to manage the increase in power flows in the region and avoid the high cost actions on interconnectors seen in July 2022.

We have argued in our Net Zero Market Reform programme that nodal pricing, which reveals the value of electricity at high locational and temporal granularity, could be beneficial to enable market participants to mitigate thermal constraints, particularly in operational timescales. The Department for Business, Energy & Industrial Strategy (BEIS) are also considering nodal pricing as one of several options to improve locational signals in its Review of Electricity Market Arrangements (REMA). We think long term, this solution could support with addressing thermal constraints and will reduce the need for additional network build. We are introducing a local constraint market in early 2023 to address high constraint costs between Scotland and England. This will help to inform our thinking on local markets.



Operability Strategy Report / Executive Summary / 14

# Reliable Network Summary

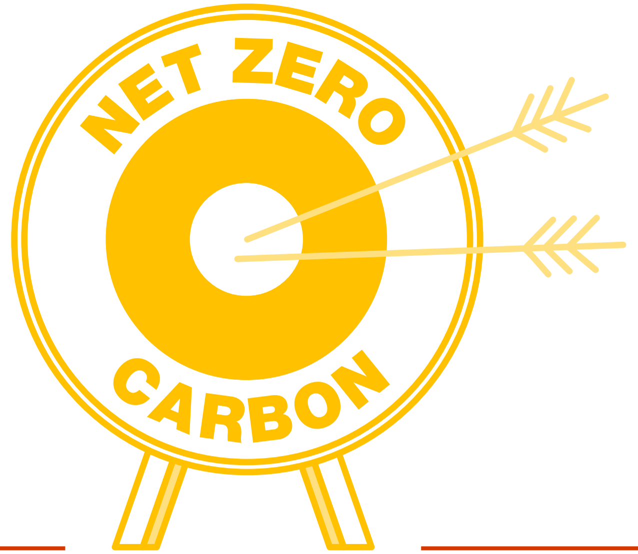
## Restoration

In the unlikely event that the electricity system fails, and the lights go out, we have a robust plan to restore power to the country as quickly as possible. Historically, the electricity system has been dependent on large, dispatchable generation to provide restoration services. Less dispatchable generation means that we need to ensure restoration services can be provided by a range of users in the future. The enormous growth in Distributed Energy Resources (DER) presents an opportunity to develop a radically different approach to system restoration. Greater diversity in the provision of restoration will improve resilience and increase competition leading to reductions in both cost and carbon emissions. Future diversity of service providers will also create operational challenges due to the complexities of managing a system with more variable sources of generation as well as a variety of providers. We need to ensure that engineering solutions, organisational coordination and commercial and regulatory frameworks can all work together to ensure resilience and flexibility in the operation of the network.

The Grid Code has always required that we have the capability to restore the system, but has had limited detail as to what that meant. In April 2021 this changed when BEIS announced their intention to strengthen the existing regulatory framework by introducing a new Electricity System Restoration Standard (ESRS). The ESRS requires that we can restore 100% of GB electricity demand within 5 days, with 60% of regional demand having been restored within 24 hours. These requirements should be implemented by December 2026.

We have worked with industry to enable DER to provide restoration services through our Distributed Restart innovation project. The three-year project has been extended towards the end of 2022, to enable the completion of the power engineering live trials. We will take learnings from the project to manage future challenges, in order to implement the requirements of the ESRS directed by BEIS and Ofgem in 2021. The technical, organisational and commercial challenges that we need to resolve are being addressed through GC0156 and specific workgroups have been set up to focus on each area (such as markets, funding, regulatory frameworks and modelling tools).

Looking forward and the future challenges will be to integrate the growing offshore networks into our restoration solutions. The System Operator-Transmission Owner Code (STC) does not currently recognise offshore networks as contributing to Restoration so this will need to be considered as part of the Offshore Network Design and HND work.




Operability Strategy Report / Executive Summary / 15

# Balancing the System Summary



## Frequency

Falling inertia levels, increasing largest loss size and high RoCoF levels are driving many of the current and future frequency challenges. In addition, supply and demand are becoming increasingly variable. This is making system frequency more volatile and unpredictable. The introduction of FRCR last year was a paradigm shift in how we manage frequency as it introduced a probabilistic approach that increases end consumer benefit compared to the previous deterministic approach.

We are tackling these challenges through our new suite of reserve and response services. Dynamic Containment, Dynamic Regulation and Dynamic Moderation are all live on the system. Looking forward, several new reserve services will be launched.

- Quick Reserve will be used to recover frequency back towards 50Hz, mainly during normal operating conditions
- Slow Reserve will replace Short Term Operating Reserve (STOR) which will recover frequency to +/- 0.2Hz within 15 minutes
- Balancing Reserve will provide flexibility in real-time to ensure balance between supply and demand

These reserve services will be launched soon through our response and reserve reform programme.

The size of our frequency requirements are dictated by the inertia levels on the system and the size of both generation and demand losses. These requirements may change and are heavily impacted by how the system evolves. The following table sets out our 2025 requirement and assumes the inertia provided by the market falls as low as 102GVA.s:

| Frequency service | System need | Required |
|---|---|---|
| Dynamic Regulation and Dynamic Moderation | **Regulate** steady-state frequency within the statutory limits of +/-0.5Hz | up to 300MW each |
| Dynamic Containment | **Contain** the frequency for events within standards | up to 1,400MW |
| Quick Reserve | **Recover** frequency back towards 50Hz, mainly during normal operating conditions | up to 1,400MW |
| Slow Reserve | **Restore** frequency to the operational range (+/-0.2Hz) within 15 minutes | up to 1,400MW |
| Balancing Reserve | **Flexibility in real-time** to ensure balance between supply and demand | up to 2500MW |

We have identified a gap within our new suite of services due to the ending of monthly procurements of dynamic Firm Frequency Response (FFR) and secondary static response. A future service is being designed to recover frequency to +/-0.5Hz within 60 seconds following large scale losses. We have been working through options to meet this need and a new service provisionally called Static Recovery has been identified.

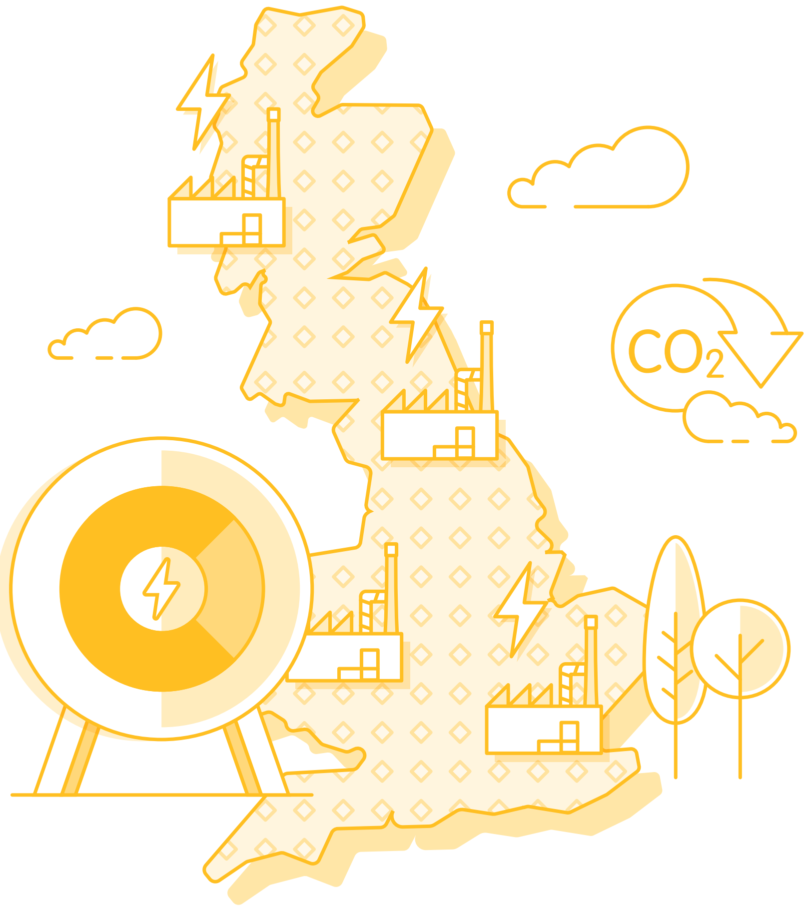
Greater locational fluctuations in frequency may occur due to lower inertia and increased largest loss size. We're investigating any potential requirement and solutions to help develop our future frequency strategy. This potentially could lead to a requirement for regional frequency products.

Operability Strategy Report / Executive Summary / 16

# Balancing the System Summary

## Within-day flexibility

Within-day flexibility is a new dimension of operability that has been added into the Operability Strategy Report this year. The operability challenge we are highlighting is how to manage daily peaks and troughs of supply demand lasting a few hours. We have defined Within-day flexibility as the ability to move demand (and supply from storage) within a 24-hour period. This flexibility will be used to ensure energy balance between more variable sources of generation and inflexible demand. These timing driven imbalances will grow rapidly over the next 10 years with increasing volumes of renewable generation and electrified demand. The system will need the ability to shift demand through time because without it, there will be an increased need to curtail renewable generation and an increased reliance on dispatchable generation, which will increase costs and emissions. In addition, the ability to adjust demand and network flows will help with our other operability requirements. The capacity of Within-day flexibility is currently small but will grow rapidly over the next 10 years. FES shows that by 2030, the system is expected to have 25-45GW of Within-day flexibility mainly from smart charging of electric vehicles, vehicle-to-grid, smart electric heat, smart domestic appliances and battery storage with duration of a few hours. This growth in Within-day flexibility will be driven by changes in market arrangements such as the introduction of market wide half hourly settlement that will increase consumers exposure to time of use signals.




Operability Strategy Report / Executive Summary / 17

# Balancing the System Summary

## Adequacy

Adequacy measures whether there are sufficient available resources to meet electricity demand throughout the year. In Great Britain, this has traditionally meant having sufficient margins when demand is highest in winter.

We commissioned AFRY to undertake a long-term adequacy study to assess the risks to security of supply in a fully decarbonised power system and the resources needed to ensure adequacy in the 2030s. The study examines four different potential portfolios of resources – utilising different combinations of nuclear, CCS, hydrogen power generation and batteries. The purpose is not to identify a definitive pathway, or resource mix, for GB; but rather to explore the range and mix of options that could ensure adequacy, the implications of them and some of the trade-offs that might be required. This is a first step towards understanding the scale of the challenge facing GB.

The full report is available on our website and the key findings are:

- There is no trade-off between adequacy and meeting net zero but we need to bring forward investment in clean, reliable technologies.
- Understanding risks due to weather patterns will become increasingly important to ensure adequacy in a fully decarbonised system with high levels of weather-dependent generation.
- New modelling approaches and metrics will be required to assess risks to adequacy in a fully decarbonised power system.
- It will become more important to consider adequacy in the context of developing the right markets, the right networks and future operability challenges to be confident that adequacy is ensured in a cost-effective way.

There are also operability impacts to consider. Whilst there are many different pathways that can provide similar levels of adequacy, there are significant differences in their operability impact throughout the year. For example, a resource mix with high levels of renewables combined with significant levels of less flexible generation, will have a much higher level of surplus energy and renewable generation curtailment. While this poses little operational risk to security of supply, the need for curtailment could increase operational costs substantially.



Operability Strategy Report / Executive Summary / 18

# How to get involved

## We want to work with you!

Our strategy is ambitions and transformative. It is vital for making sure we can continue to operate a safe, secure and reliable electricity system, and deliver against our zero carbon by 2025 ambition while maximising benefits for the consumer and your input and support is critical.

Throughout the main body of our report, you will find links to specific opportunities to get involved in all key areas of our work. We would also welcome to your comments and feedback on our overall approach to our operability challenges or any specific feedback on the report content. Please get in touch by emailing us at sof@nationalgrideso.com

## System Operability Framework publication plan

The System Operability Framework (SOF) takes a holistic view of the changing energy landscape to assess the future operation of Great Britain's electricity networks.

The SOF combines insight from the Future Energy Scenarios with a programme of technical assessments to identify medium-term and long-term requirements for operability. The table below details the publications planned over the next few months.

Please visit the SOF webpage for details of past and present publications.

| Reports | Overview | When to expect |
|---|---|---|
| Power Quality in Electrical Transmission Network | Power quality is critical to the performance of equipment connected to the electricity network. There is direct correlation between power quality and system strength. The stronger the system strength, the easier it is to manage the power quality to the relevant standards. As more asynchronous generation connects to the system, the system strength continues to decline. This report will provide an outlook of the changes in the power quality of the electricity network. | Mar 2023 |
| System Strength | How to effectively manage system strength of the GB system with a future high penetration of inverter-based resources (IBR) is important for stable operation of the system. This report shares our thinking about how system strength should be defined and managed in an IBR dominated system. | May 2023 |
| Management and Mitigation of Oscillations on the GB Transmission System | Since oscillations were observed on the SSEN-T transmission system in August 2021, detailed investigations have been taking place reviewing:<br>• Network analysis to understand the drivers of the oscillations.<br>• Assessment of indicators to be used as a screening technique to determine areas at greater risk of oscillatory events; and<br>• Application of system monitoring tools to give greater visibility of events<br>This report will share findings and insights from our investigations. | Aug 2023 |
| GB Grid Forming Development | Grid Forming is widely recognised as a promising technology for global net zero energy transitions. This report introduces the GB Grid Forming strategic developments that will help address existing or potential operability challenges on the GB system. In particular it will look at the interaction with the decline of system inertia and the reduction in system fault levels. | Nov 2023 |

Operability Strategy Report / Executive Summary / 19

# Zero Carbon Operability

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# Zero Carbon Operability

**Great Britain is one of the fastest decarbonising electricity systems in the world and as the system operator we have an ambition to be able to operate the network the network using 100% zero carbon electricity by 2025.**

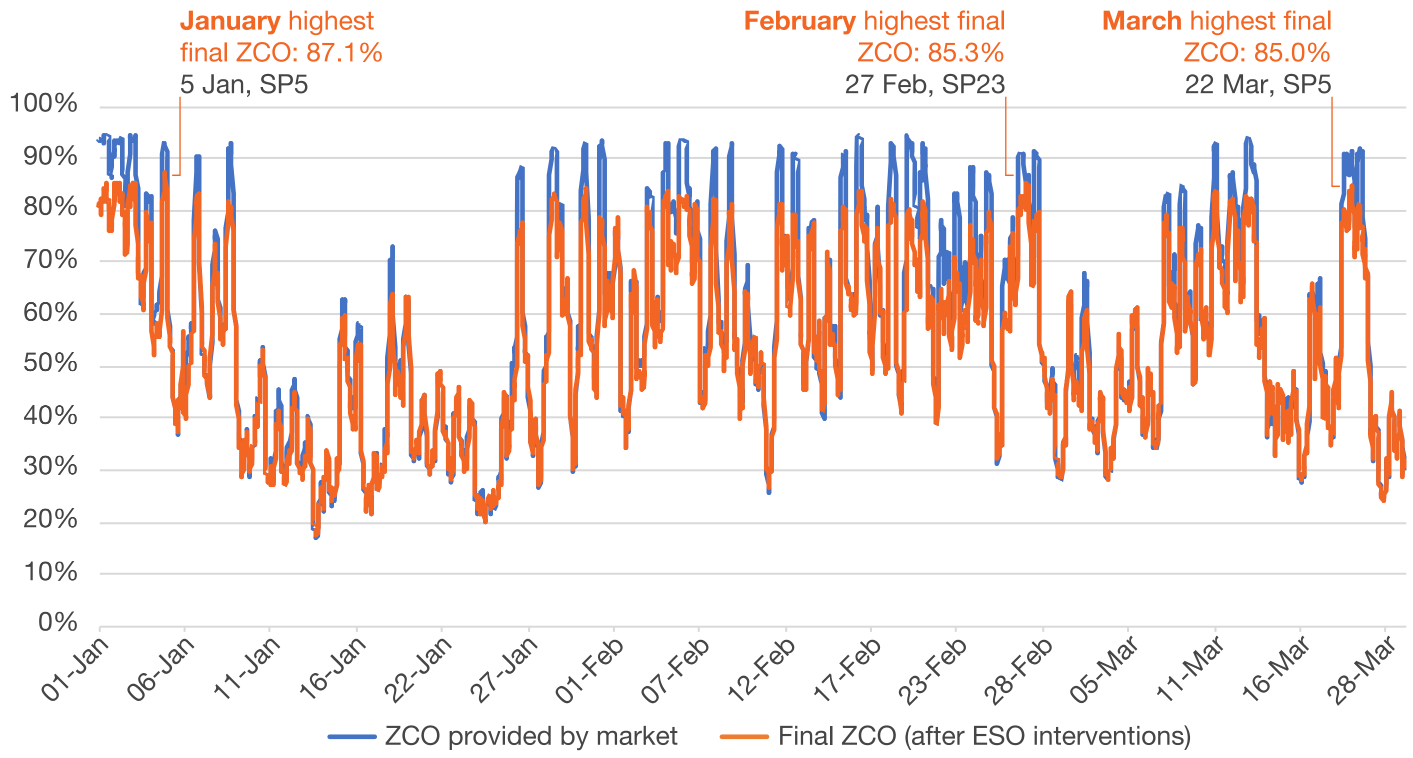
To do this we are pushing forward innovative, world first approaches to transform how the power system operates. We are delivering frequency services that are fit for operating a zero carbon network where system frequency will, at times, be more variable. Our stability and voltage pathfinders reduce our reliance on dispatchable generation for critical transmission system services. We can already maintain our system restoration capability without warming or running fossil fuelled generation.

**Across all our workstreams, we will be ready to meet our 2025 zero carbon ambition.** These innovative approaches and the plans we have put in place across each operability workstream, mean that by 2025, there could feasibly be periods where we will be able to operate a zero carbon system if the transmission generation scheduled by the market is zero carbon. Initially this maybe for a few settlement periods throughout the year, but these periods will grow as our capability to operate a zero carbon system expands and the market provides more zero carbon dispatch solutions. This could potentially happen in a manner similar to the phasing out of coal, where we initially observed rare zero coal settlement periods. Within a few years after coal began to come off the system, these periods started to become the new normal.
We assess progress against our ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate before and after our actions. Zero carbon generation includes hydropower, nuclear, solar, wind and pumped storage technologies. We share this progress through the Zero Carbon Operability (ZCO) indicator:

$$ZCO(\%) = \frac{\text{(Zero carbon transmission connected generation)}}{\text{(Total transmission connected generation)}} \times 100$$

This year our ability to operate a zero carbon network has increased. We saw an increase to a new zero carbon generation maximum of 87% on 5th January 2022 after our operational interventions (shown in the chart). During these periods, we synchronised six carbon units for system reasons (voltage and minimum inertia). However the need for these additional carbon units will be removed for settlement periods such as these, through our on-going voltage and stability work. This means that by 2025 we will have the ability to operate a zero carbon network, reducing our reliance on carbon generation for ancillary services and also reducing operational costs. Please see following the essential activity that we have already completed and what is left to do to achieve our ambition.

## Q4 ZCO detail by Settlement Period





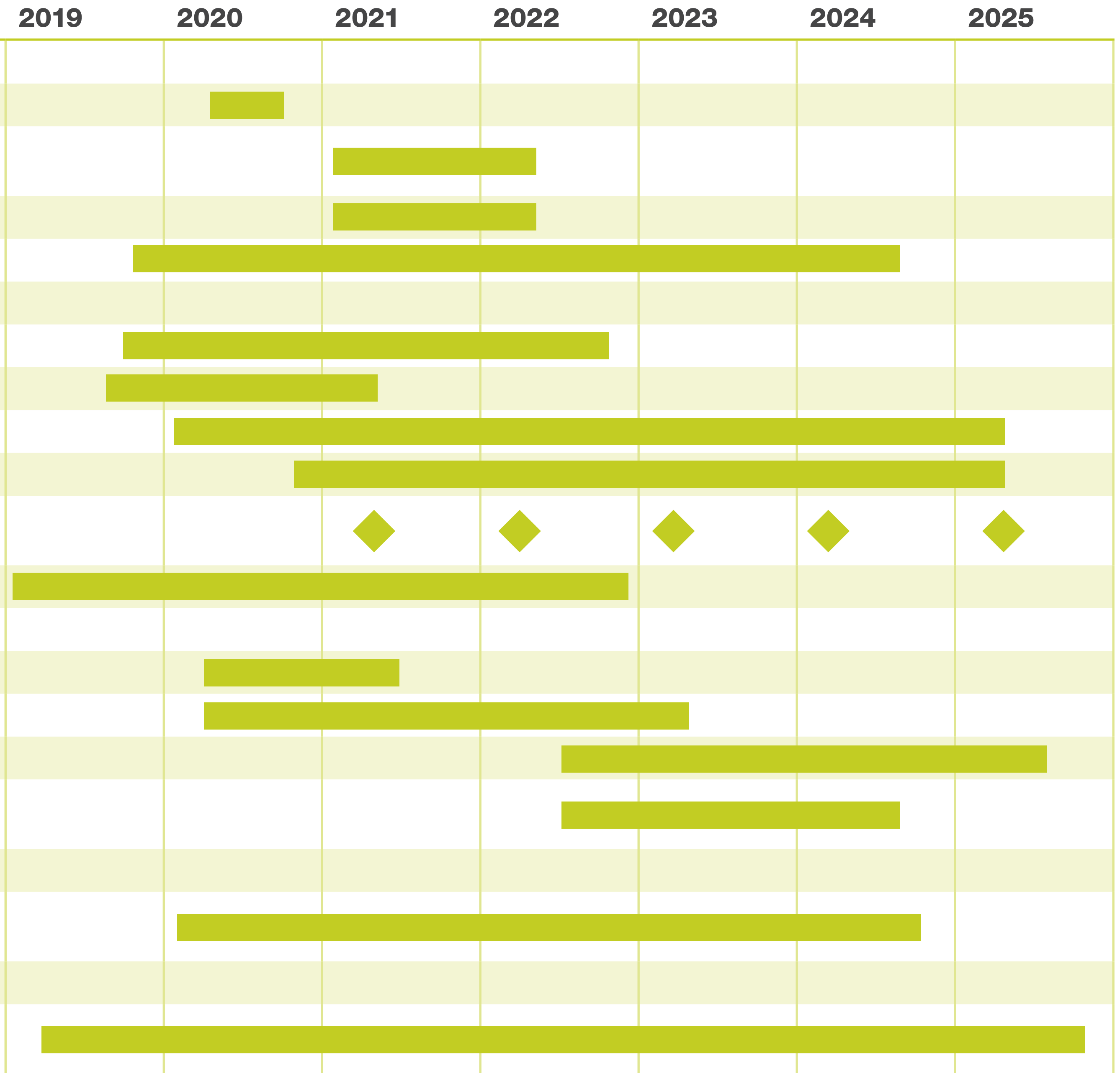
Operability Strategy Report / Zero Carbon Operability / 21

# Zero Carbon Operability

## Activity essential for 2025 zero carbon operation

Looking back at the journey from setting our zero carbon ambition in 2019 to develop the capability to operate zero carbon in 2025, the following are the key activities which have made operating at zero carbon possible.

| | |
|---|---|
| **Frequency** | |
| DC | Dynamic and fast acting response product to manage larger losses at lower inertia levels |
| DM | Dynamic response to better manage large changes in intermittent generation at lower inertia levels |
| DR | Dynamic response to better manage pre-fault frequency at lower inertia levels |
| Reformed Markets | Market reform across all response and reserve products to facilitate new zero carbon operation |
| **Stability** | |
| ALOMCP | Removes the risk of DER activation at lower inertia levels |
| Phase 1 | 12.5GVAs of inertia |
| Phase 2 | 6.5GVAs of inertia and 11.5GVA SCL for Scotland |
| Phase 3 | 17GVAs of inertia and 12.7GVA SCL for E&W |
| FRCR | Enables the enhancements from the Frequency provisions to change how we operate the system at lower inertia |
| Inertia monitoring | Implementing first of its kind inertia monitoring tools, providing instantaneous, real time data |
| **Voltage** | |
| Mersey | Reduce the reliance on a single CCGT for voltage in one area |
| Pennines | Expand the learning to cover a larger area and reduce reliance on a number of units |
| E&W | Cover the whole of E&W to ensure no reliance on machines to manage voltage |
| Efficiency | Increased access to existing capability through changes to codes and developments with the Transmission owners |
| **Thermal** | |
| Efficiency | Five point plan and Constraint Management Pathfinders to increase zero carbon capabilities |
| **Restoration** | |
| ESRS Services | Ensured that all ESRS services are in place and do not require units to be 'warmed' to provide the service |




Operability Strategy Report / Zero Carbon Operability / 22

# Zero Carbon Operability

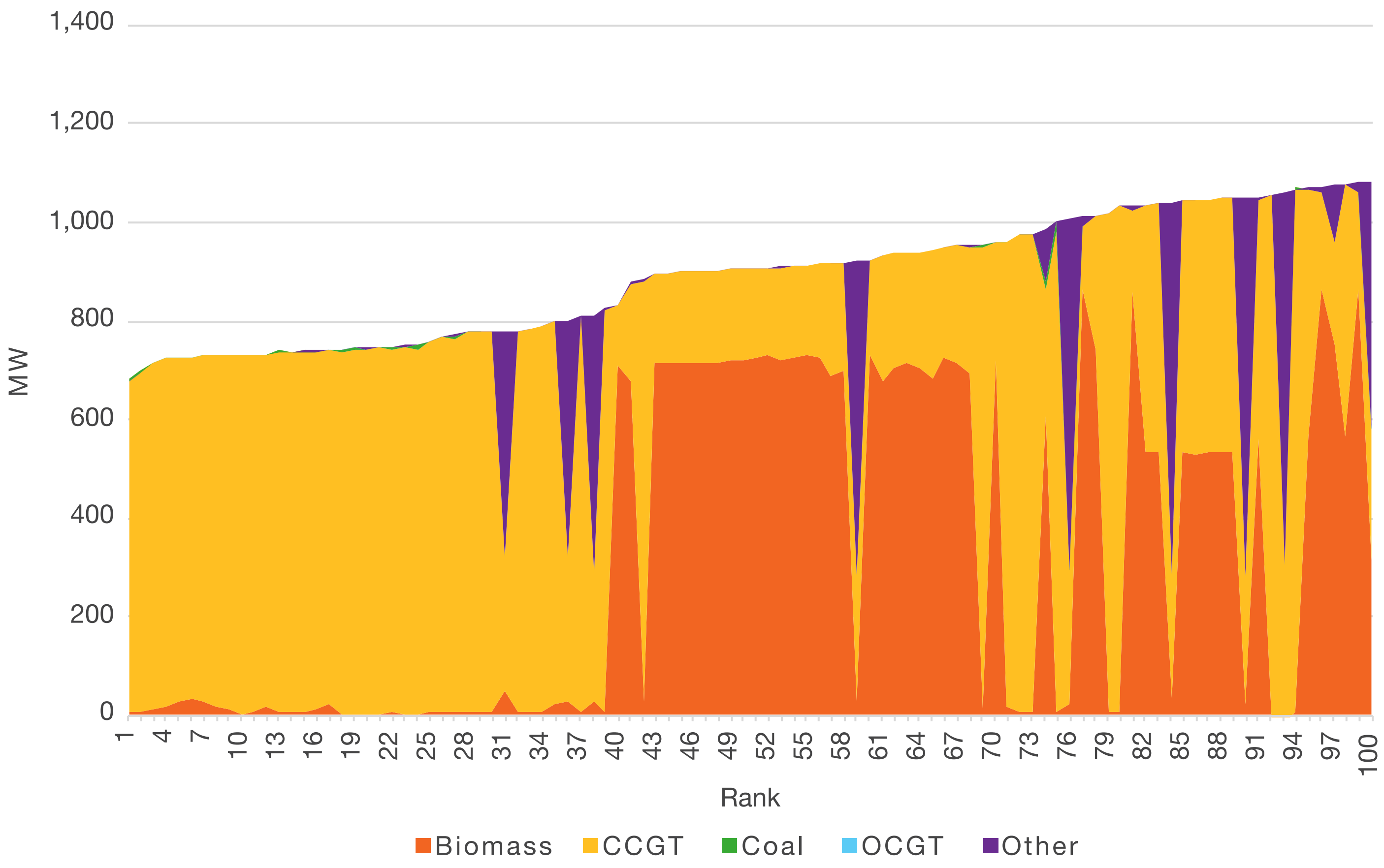
ZCO is highest when it is windy with significant contributions from nuclear, pumped storage and hydro. It will be reduced by our actions to alleviate system constraints such as when we constrain zero carbon generation from the system and add on fossil fuelled generation such as gas or biomass to meet our response, inertia and voltage requirements.

By 2023 the maximum ZCO limit will rise to 87% - 90%. This increase is due to the work we are doing to drive towards our ambition. For example, our new response products, the stability pathfinders, the implementation of the Frequency Risk and Control Report methodology, the voltage pathfinders and reactive reform. All of these developments are increasing our ability to operate a zero carbon system by either increasing the operability envelope where secure system operation is possible, or by enabling new zero carbon providers for the ancillary services we need. As the work continues through 2023 and 2024, we expect that this will further increase our ability to operate a zero carbon system.

By 2025 we expect that periods of 100% zero carbon operation will be possible, albeit in specific conditions. There is a zone where operational interventions are minimised because system conditions are favourable. Transmission demand will be neither too high or low, but can be supplied exclusively from interconnectors, nuclear, wind and solar. Stability and voltage requirements will need to be met without dispatching fossil fuelled generation. This results in a ZCO operability window where demand is between ~25GW and ~65GW, but more likely at the lower end of this range. This is more likely to happen during Spring or Autumn, or during the Christmas break, when it is windy and demand is lower.

Our ambition is to be able to operate a 100% zero carbon system when the market delivers such a solution. However since April 2021, there have been no settlement periods where the market has delivered a 100% zero carbon generation mix. For every settlement period, there has always been 500MW+ of either biomass and/or gas. The closest has been where there was 95.5% zero carbon generation in November 2021 and the lowest carbon MW was 679MW in August 2021. The chart shows the carbon generation mix for the 100 settlement periods with the lowest carbon MW since April 2021.

## Where the market supplied carbon MW is minimised





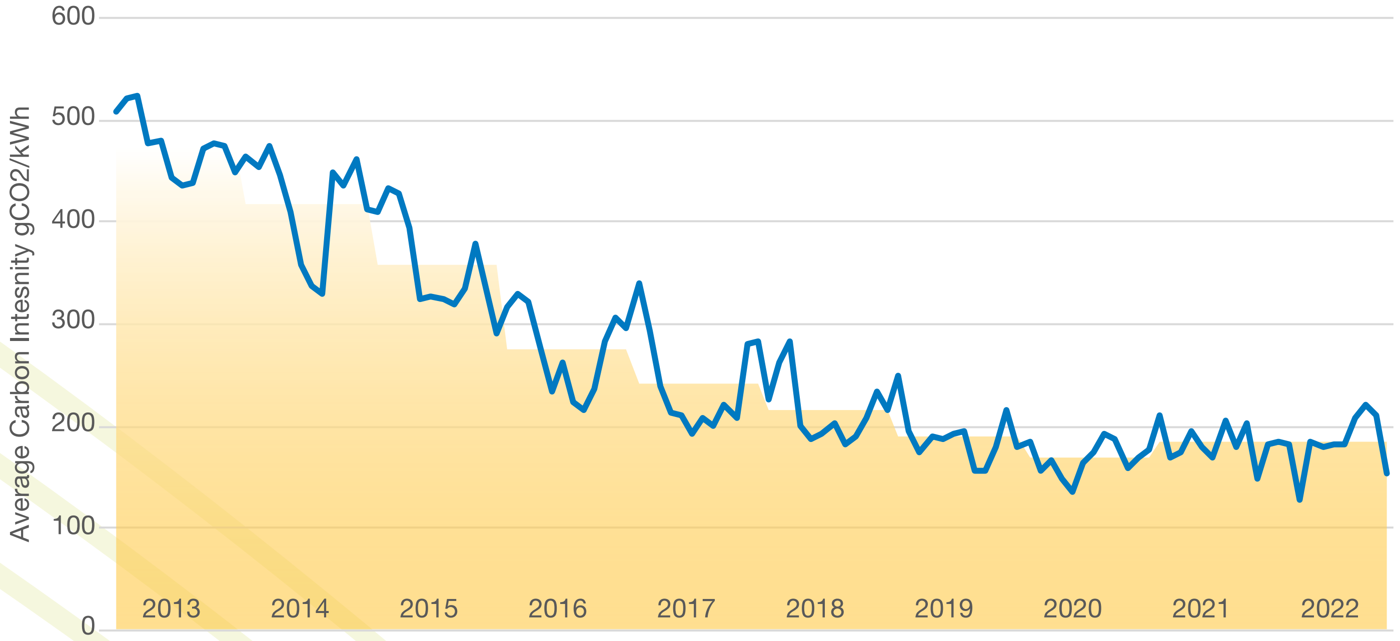
Operability Strategy Report / Zero Carbon Operability / 23

# Zero Carbon Operability

Our focus is to ensure the lowest cost solution when operating the network. The price of carbon is fed through to the prices we see through other regulatory and market mechanisms. Therefore, while our ambition is about preparing the ESO to operate a zero carbon system if market forces deliver the conditions, importantly we will not schedule plant to meet our ambition if it increases overall consumer costs.

Whilst our ability to operate a zero carbon system has continued to increase, the actual carbon intensity of the system has temporarily plateaued rather than continue the steady decline that we have seen over the last few years. This is shown in the following chart. This is because the growth in renewables has been offset by the decommissioning of the nuclear fleet and the increase in interconnector exports. This has increased the running time of fossil fuelled generation.

## GB Carbon Intensity gCO2/kWh




More information on our zero carbon progress can be found on our dashboard.nationalgrideso.com and website nationalgrideso.com. We also have a free app with more data including a regional carbon intensity breakdown, electricity records and the cleanest time of day to use power. This can be downloaded via Google Play and the App store or see our website.

Operability Strategy Report / Zero Carbon Operability / 24

# Reliable Network

ESO

# Managing locally to deliver nationally



**Operating the national electricity transmission system to deliver power safely and reliably requires management of power system characteristics locally, right across the network. The Thermal, Voltage, Stability and Restoration workstreams ensure that we can:**

- Manage power flows across constraint boundaries
- Maintain voltage within safe limits
- Ensure the system is stable enough to cope with faults
- Recover the power system in the event of a partial or total shutdown of the network

We operate the transmission system second by second, monitoring characteristics of a high voltage electricity system and taking actions to keep these characteristics within safe limits of operation. These limits and requirements are set out in the Security and Quality of Supply Standards (SQSS) and the Electricity System Restoration Standard (ESRS).

The physics of a high voltage power system require certain system services to be delivered at, or near, the point of need. Historically, most of these needs were met by large dispatchable generation, delivering reactive power for voltage management, and short circuit current for managing faults. These generators were well spread around the network and near to demand centres, which made them well placed for restoring the network following a power outage. It also minimised the actions required to resolve thermal constraints.

Operability Strategy Report / Reliable Network / 26

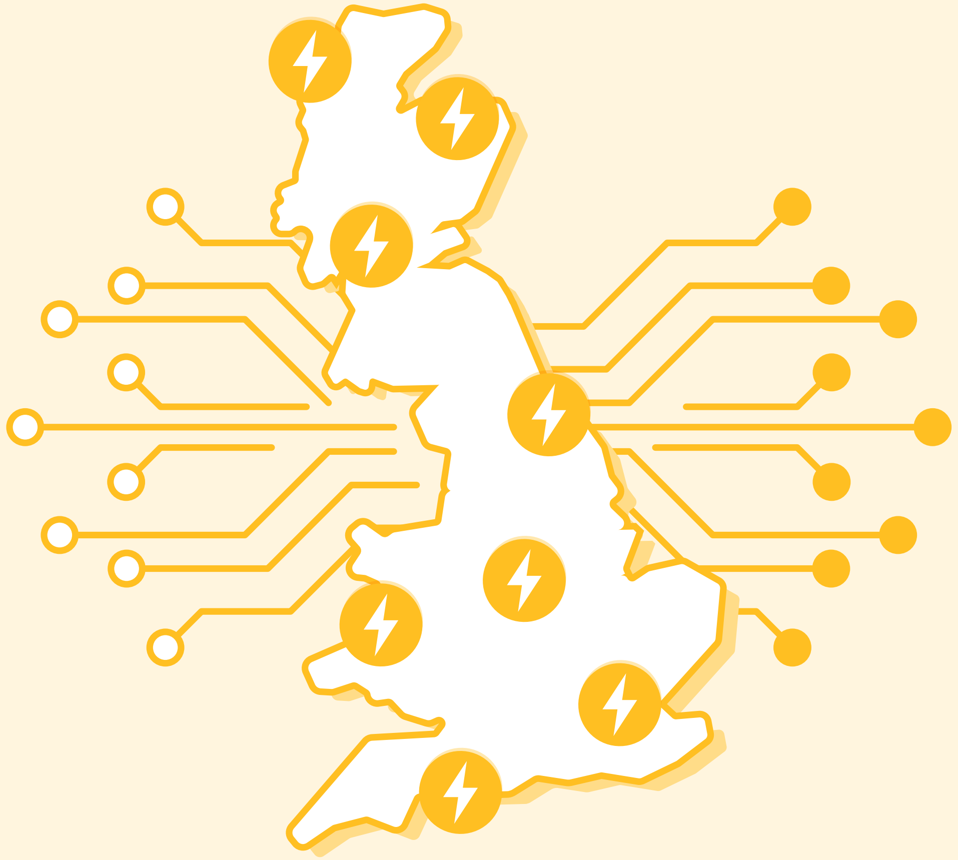
# Managing locally to deliver nationally

The system services used, both historically and now, to manage the network are not directly valued by the energy market. We are the sole buyer of these services and currently must procure them to maintain a safe, reliable, and compliant network. Therefore, we are wholly responsible for the resilience of these services and ensuring that they are delivered effectively and efficiently for consumer benefit.

As the electricity system decarbonises, we have access to less dispatchable generation but we are finding new sources to meet these challenges and locational needs.

- Power must be able to flow right across the network, from wind generation in Scotland to interconnector exports in South East England
- The network must be able to be restored using more variable sources of generation and assets on the distribution networks, whilst meeting the future restoration standard
- New sources and providers of reactive power and short circuit current are needed in the right locations of the network

These reliable network workstreams cover the challenges in more detail and the potential solutions available.




Operability Strategy Report / Reliable Network / 27

# Stability

# Stability

## Summary

As decarbonisation of the electricity system leads to less dispatchable generation and subsequent loss of traditional stability sources, we need to introduce alternative capabilities that can provide stability services separately from active power. The reduction of the inherent stability of the system means we need to ensure that dispatchable generation can provide system stability in a way that supports our zero carbon ambition, or that asynchronous generation can be adapted to provide a more stabilising effect on the system.

We also need to continue to ensure standards for capabilities like loss of mains protection and fault ride through remain fit for purpose as the system changes.

## What do we mean by stability?

**Stability is the inherent ability of the system to quickly return to acceptable operation following a disturbance. The term is used to describe a broad range of topics, including inertia, short circuit level and dynamic voltage. If the system becomes unstable it could lead to a partial or total system shut down leading to the disconnection of consumers.**


Operability Strategy Report / Reliable Network / 29

## What are our obligations and what are the future operability challenges?

We have an ambition to operate the system carbon free for periods by 2025, in order to achieve the government's target to operate a fully decarbonised electricity system by 2035. Decarbonisation of the electricity system leads to more asynchronous generation. This generation does not have the same inherent stabilising effect on the system as dispatchable generation. This results in a steady decline in the inherent stability on the system meaning we need to learn to operate a more dynamic system than has traditionally been the case.

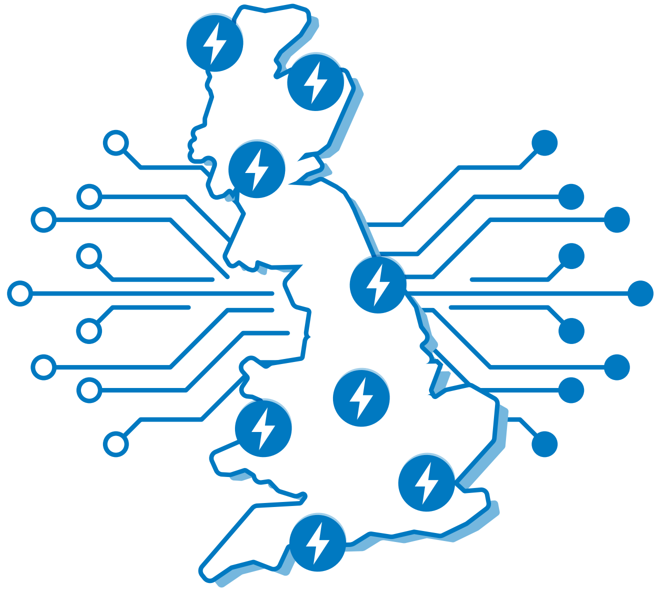
The Security and Quality of Supply Standard (SQSS) requires that we operate the system such that it remains stable following specific secured events. These obligations are enduring, and we are required to ensure they are met at all times even when system conditions change. The term stability is used to describe a broad range of operational and technical challenges, the most significant are covered here.

### Inertia

By 2025, our ambition is to maintain a minimum inertia of 102GVAs, based on a future state of securing a largest loss of 1800MW and keeping Rate of Change of Frequency (RoCoF) within 0.5Hz/s.

Today, we operate the system at 140GVAs which keeps RoCoF below 0.125Hz/s for a loss of 700MW. This policy was established as, historically, RoCoF has been the determining factor for managing system inertia. 140GVAs ensured that RoCoF was no greater than 0.125Hz/second and ensured no subsequent disconnection of embedded generation. This policy was implemented before recent operational changes to the system including the Accelerated Loss of Mains Change Programme (ALoMCP), the implementation of Dynamic Containment (DC) and the Frequency Risk and Control Report (FRCR), a combination of which means we have been able to relax our policy on how we manage large losses and associated frequency risks.

A combination of these changes also means that we can begin to review the minimum level of inertia required on the system as the current 140GVAs level is now less closely linked to system conditions, given the progress made across our frequency strategy in the areas mentioned previously. This will enable a gradual reduction from current 140GVAs operational limit, to the future 102GVAs.



# Stability

## Short circuit level (SCL)

In a system dominated by synchronous generation, short circuit current is provided by synchronous machines which are capable of setting their own voltage waveform. A system with a high penetration of synchronous generation means it is more capable of maintaining voltage and frequency during a fault, or can 'ride through' faults.

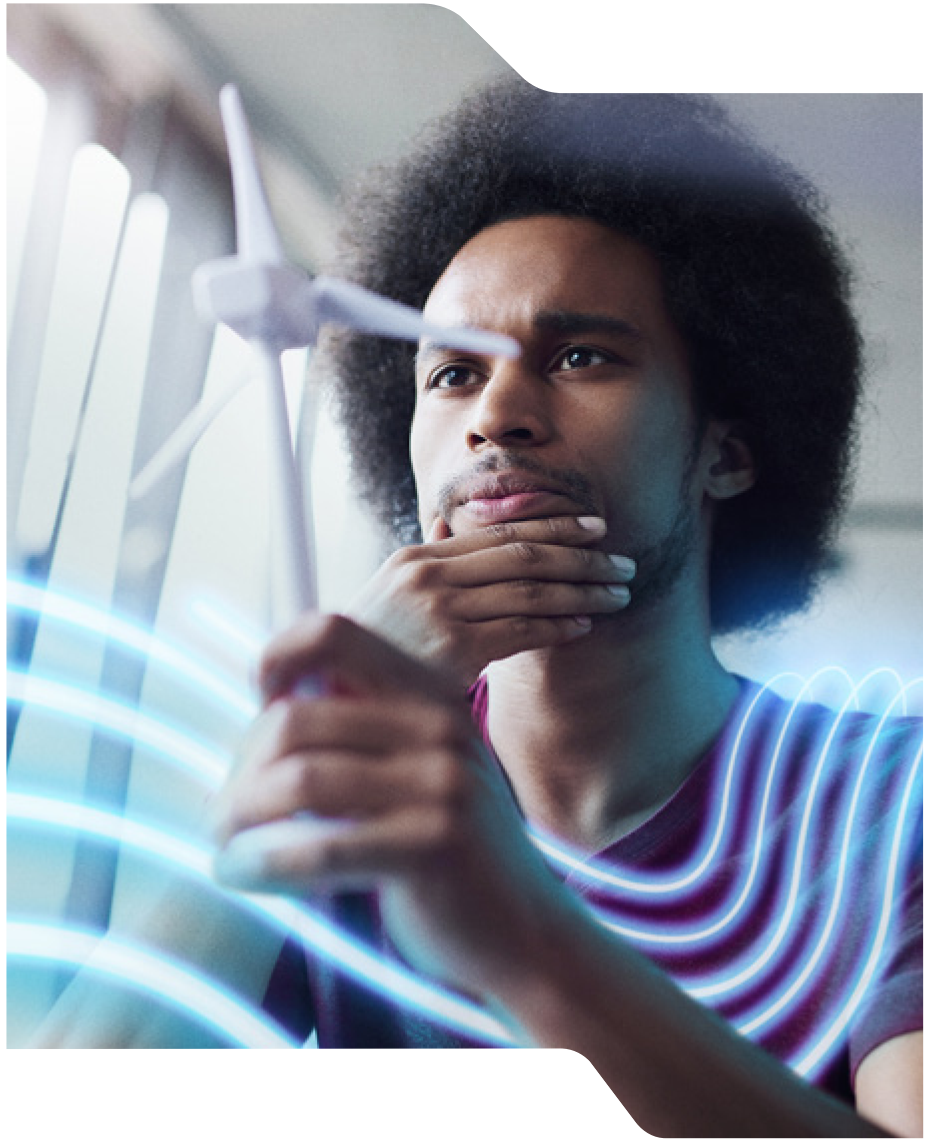
Today we see more short circuit current coming from more asynchronous generation. During a fault, this technology will act as a current source, injecting current into the system but will not set a voltage waveform. Inverter based generation therefore does not contribute to system strength. More asynchronous generation (without Grid Forming capability) leads to declining system strength, therefore impacting system stability. We must find alternative ways of managing system strength where the current trend is declining short circuit levels.

Short circuit ratio (SCR) is a widely used measure of system stability, calculated as:

$$\text{SCR} = \frac{\text{SCL (MVA)}}{\text{Connected IBR Capacity (MVA)}}$$

We currently calculate the SCR at each busbar on the network and set this against a defined threshold to highlight areas in the network where system stability is considered to be low. The threshold that we currently adopt is based on studies conducted by CIGRE whereby SCR should be ≥2. This threshold is applied as an indicator for further detailed studies to be conducted in an area, rather than a specific indicator of system instability.

It is also widely acknowledged that there are limitations to the 'traditional' indicator of SCR and whilst there are numerous other options for more accurate metrics of system strength, there is no single universally agreed methodology within industry. There are numerous factors to consider when looking to identify the most optimal solution (such as system impedance or interaction factors) and we have been working with other TSOs across the world, as well as other Transmission Owners to review short circuit level methodologies for managing systems with ever increasing asynchronous generation.




Operability Strategy Report / Reliable Network / 31

# Stability

## What capability do we need to meet these changing operability challenges?

The stability challenges seen today and into the future, are primarily caused by less dispatchable generation, more asynchronous generation and more variable sources of generation.

We anticipate that technologies with grid forming capability will be a significant contributing factor to future stability of the system, alongside other stability services to effectively manage a net zero power system. The non-mandatory specification in the Grid Code provides guidance on minimum requirements for enhancing the capability of asynchronous generation to act with similar characteristics to synchronous generation. We anticipate that future market arrangements for stability services will form the basis of where future grid forming technology could be procured.

In addition, we need to develop both modelling and analytical skill required for further detailed Electromagnetic Transient (EMT) simulations. This capability will support with studying the increasing challenges regarding system stability and the need to further analyse areas of the network where stability issues may emerge. We have set out plans to enhance this capability within our RIIO2 Business Plan (deliverable A15.6).

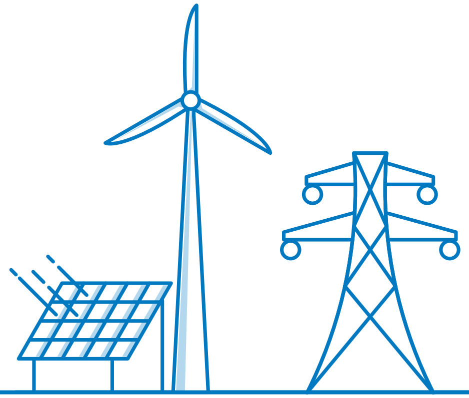
Alongside both of these new capabilities to support future system stability, we will need to standardise the process for defining stability requirements, by creating a year-round process for analysing the ever-changing need. This will provide both transparency for industry when aligned with a future stability market, as well as consistency in future requirement setting.

## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

To identify our future stability requirements, we calculate inertia and short circuit level (post-fault voltage recovery and retained voltage) from transmission connected generation dispatched in our BID3 models. This provides a baseload level of system stability services, which we then include contributions from embedded generation and demand, as well as the three stability pathfinders, based on their planned start dates (2022, 2024 and 2025 respectively for phase 1, 2 & 3).

Operationally, our requirement to maintain system inertia at 102GVAs could be met through a combination of dispatched generation, demand and stability pathfinders. If the forecasted dispatched generation plus additional stability services were to differ from that studied, we could meet our inertia requirement by synchronising additional units. Therefore, our future requirement for inertia does not represent a compliance shortfall, however any future procurement would be conducted to ensure the most economic and efficient methods are chosen to manage our stability requirements, rather than for system security reasons.

For short circuit level, we apply a similar methodology for calculating requirements as undertaken for inertia and we also study retained voltage, phase-locked loop and post-fault voltage recovery stability. Based on the latest studies, our requirements for additional short circuit levels are sufficient until 2029. We are currently investigating the optimal solution for future procurement of stability services.



Operability Strategy Report / Reliable Network / 32

## How do requirements change under differing Future Energy Scenarios?

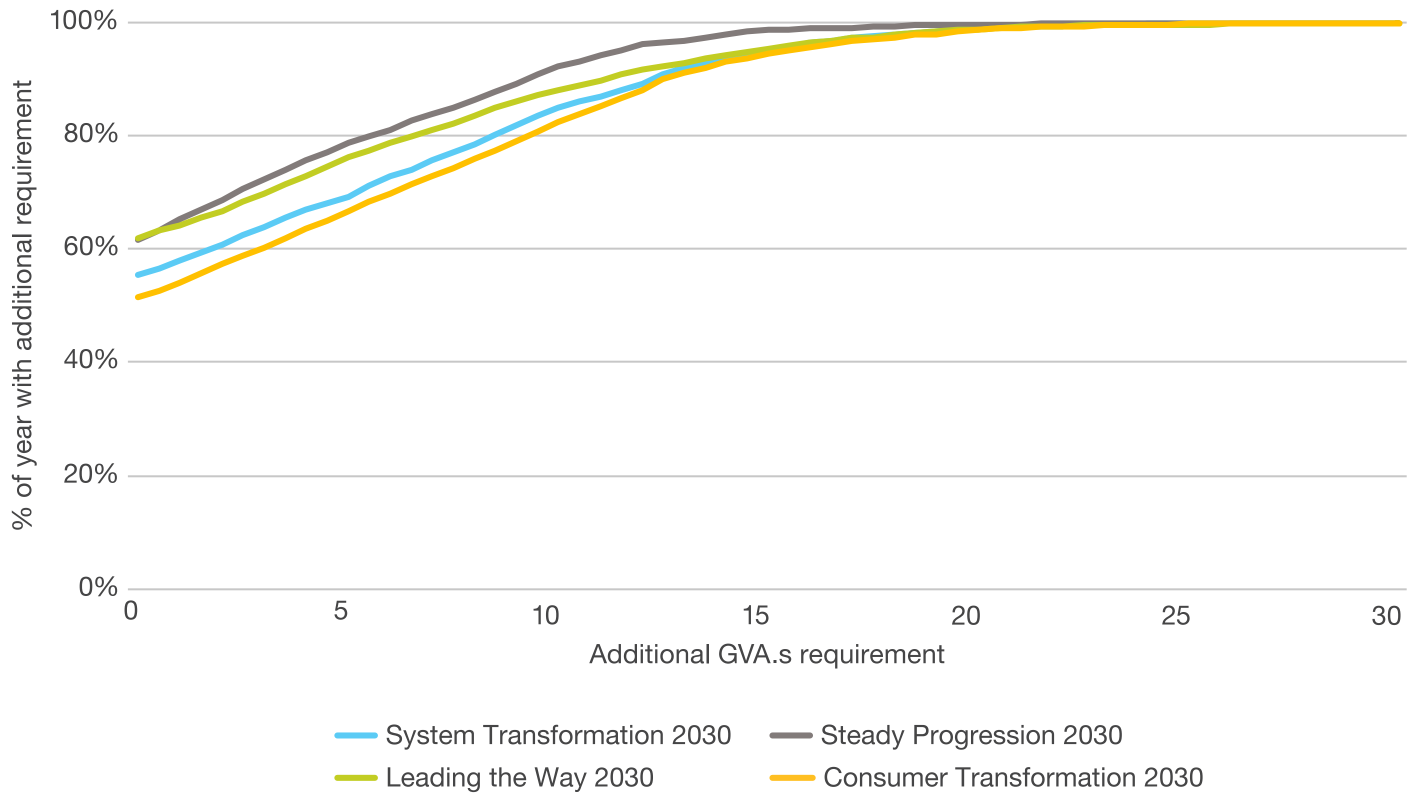
Our stability studies are based on an assessment of our four FES 2021 scenarios. The volume of dispatchable generation and the speed at which asynchronous generation is connecting to the system varies across these scenarios, and drives our requirement for stability capability on the system. These variables differ across each of the FES scenarios and whilst asynchronous generation increases across all scenarios, in Steady Progression, there is a more gradual decarbonisation of the power sector, compared with other scenarios such as Leading the Way. In Leading the Way, 40GW of offshore wind is achieved by 2029 and continues to increase through 2030's whereas in Steady Progression, only 30GW of wind is achieved by 2030.

This means that whilst the general pattern of our requirements remains broadly the same, the requirement manifests in earlier years, depending on the scenario in question. The chart provides a characteristic view of the distribution of the additional inertia requirement across the year, against the minimum requirement of 102GVAs. This is based on our forecast of baseload inertia from market dispatch, plus contribution from stability pathfinders.

As the first phase of our Stability Pathfinders (phase 1) ends in 2026, we observe an additional inertia requirement from 2027 onwards as these contracts fall away. Whilst we forecast that we have sufficient assets on the system to provide our required inertia should we need to instruct this, we acknowledge that this is not necessarily the most cost effective solution for managing future stability needs. Therefore, our Stability Market Design work is working to design the optimal procurement structure for future requirements.

In addition, given the patterns and duration of any additional inertia requirement, which generally manifests as a small, additional need for (on average) <25% of each year, it is likely that this will change the products we aim to buy in future. We are investigating how we can move towards the addition of more flexible stability products to manage system needs within shorter timeframes.

### Distribution of additional inertia requirement (2030)



## What is the next big operational challenge?

As the system continues to change, we must tackle the evolving system challenges which have historically not manifested as issues due to the dynamics of operating a system dominated by synchronous units.

### Low short circuit levels

Low short circuit level is one of the key challenges which we must continue to solve. Setting requirements for managing low short circuit levels is an evolving challenge as more asynchronous generation connects to the system. As low short circuit levels are a relatively new phenomenon, there is no codified obligations on any market parties to manage these low levels, meaning the ESO, in conjunction with industry must identify the optimal method for managing low short circuit level in future. There are numerous methodologies and inputs to consider when assessing the impacts of low short circuit levels making it a challenging area that requires input across industry.

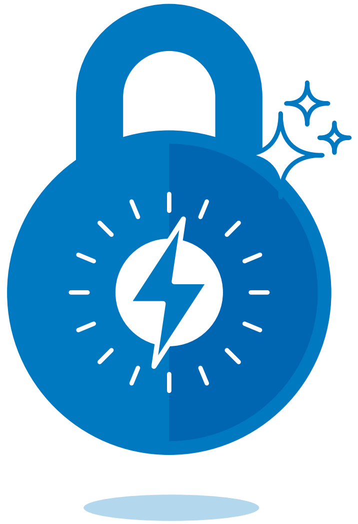
### System oscillations and control interaction of inverter-based resources (IBR)

The performance of IBRs is determined by how the inverter control system is designed and tuned. The control system, if not tuned appropriately, could cause adverse interactions between IBRs in close electrical distances.

Following events observed in August 2021, a working group was established to investigate underlying drivers for system oscillations seen in Scotland and to try to identify potential causes and mitigation measures that could be explored further. This includes enhancing Electromagnetic transient (EMT) modelling in the north of Scotland and increasing our capability to conduct detailed EMT studies so that we can fully understand these emerging operability challenges being observed on the network. Such interoperability issues could be investigated by detailed EMT time domain studies. We are also exploring the impedance-based frequency domain analysis to identify the potential issues, understand the root causes and develop the appropriate solutions.

### Future EMT studies

As part of our RIIO2 Business Plan, we have set out a plan to build the capability of developing models for EMT analysis and carrying out EMT analysis to study the control interaction behaviours and system oscillation issues. We also have a plan to engage with different stakeholders to evaluate the feasibility of co-simulation modelling between Root Mean Square (RMS) and EMT analysis tools that could facilitate EMT analysis for multiple scenarios in shorter time. Plants connecting from April 2021 are expected to provide EMT models as per GC0141 Grid Code modification, however obtaining EMT models for existing plants is a key challenge, but necessary to produce GB wide EMT models. This is a key area for future collaboration and support across industry.



# Voltage

# Voltage

## Summary

The energy transition and decarbonisation of the electricity system continues to affect voltage management across the transmission network. More reactive power capability and utilisation is required as the reactive power requirement continues to increase and available capacity decreases.

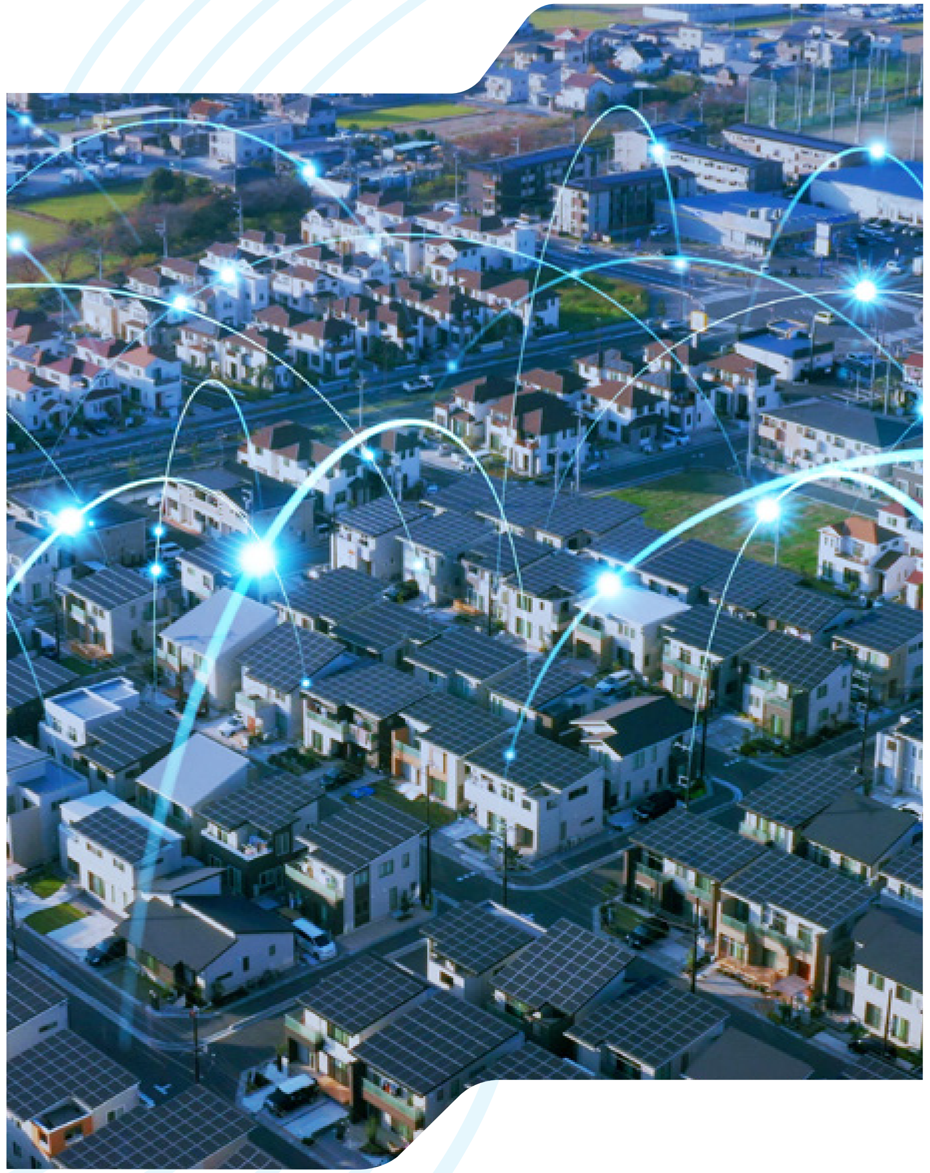
Our voltage screening report 2022 has again highlighted numerous areas where reactive capacity is reducing or voltage management costs are increasing. There is a need in both the short and medium term to increase available reactive capacity in the right locations and reduce consumer costs. Reactive utilisation costs have increased by nearly 200% in 2021/22 compared to 2020/21. Reactive utilisation has increased by 20% in the last year, but the main driver is the impact of wholesale gas prices on the default price paid to reactive power providers.

In addition to the need to reduce these costs, more reactive power capacity is needed to meet requirements in 2025 and beyond, else significant costs could be incurred synchronising generation in the right regions. This would also negatively impact our ability to meet our zero carbon operation in 2025 ambition. We have worked with National Grid Electricity Transmission in 2022 to further refine the reactive needs in 2025 and are now assessing requirements beyond 2025. We will provide an update to industry in mid-late 2023.

We continue to work with transmission and distribution network owners to find efficient ways to manage voltage on the transmission system, maintain a compliant network and enable a zero carbon electricity system by 2035.

## What do we mean by voltage?

**Voltage must be kept within set limits all across the transmission system to maintain safe and efficient operation. The absorption of reactive power helps to lower the voltage, the injection of reactive power helps to raise the voltage.**



Operability Strategy Report / Reliable Network / 36

# Voltage

## What are our obligations and what are the future operability challenges?

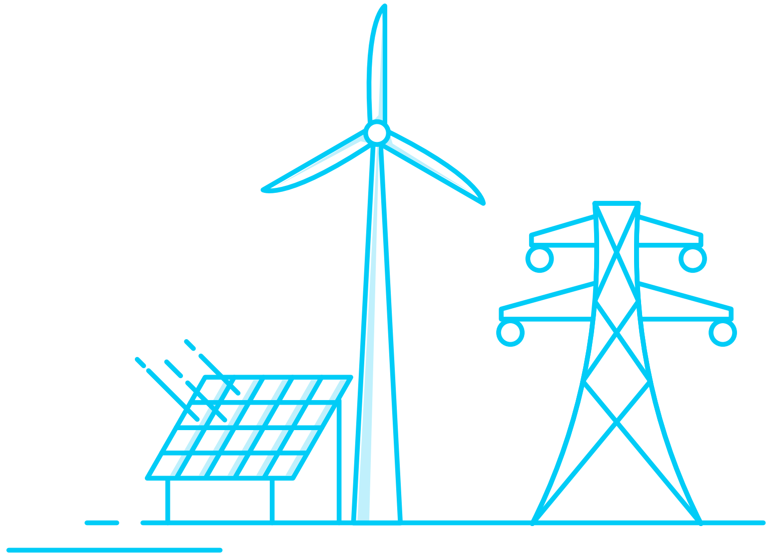
We are responsible for managing voltage levels across the transmission system. We must ensure that the Security and Quality of Supply Standards (SQSS) for voltage management are met. We must ensure that there is sufficient reactive capability available on the transmission network to maintain voltage within an acceptable range. There are obligations on us and transmission owners (TO) to build, maintain and operate a network which meets voltage criteria in the SQSS. These criteria apply in planning and operational timescales, and in steady state and post-fault scenarios.

Within the annual assessment of network capacity, the Electricity Ten Year Statement (ETYS) and Network Options Assessment (NOA), we identify when and where there are voltage needs resulting from peak power flows on the system. The ETYS assessment identifies periods of undervoltage which occur when power flows are high. Historically, undervoltage was the main operational challenge due to high levels of demand and generation on the network. The reduction in both active demand (MW) and reactive demand (MVAr) has shifted the need to manage overvoltage during the night and throughout the summer.

The energy transition is having, and will continue to have, a significant impact on voltage management across the transmission network. The need for reactive power support continues to increase and new providers of reactive power are required, in the right locations, to meet this increase. The increase in reactive power needs is driven by many factors:

- transmission circuits which are transferring much less power than their capability produce reactive power and raise the voltage
- more transmission circuits are put underground and these cables inherently produce reactive power
- reactive power was historically consumed by assets on the distribution networks, but now reactive power is produced on and by distribution networks which must then be consumed and managed on the transmission network

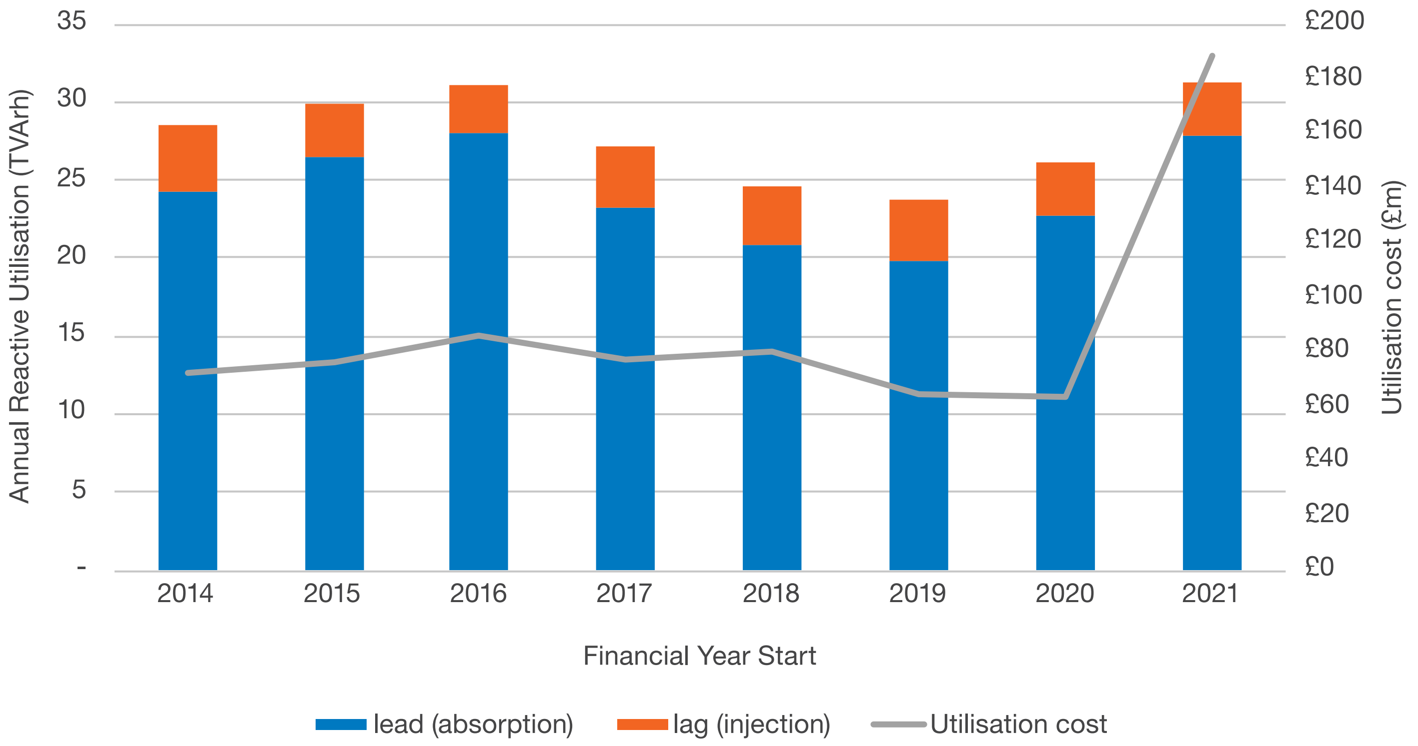
Meeting these increasing reactive needs continues to get more challenging and costly. Lower system demand and more asynchronous generation have the effect of displacing dispatchable generation. We must issue dispatch instructions to these generators so that we can access their reactive power capability and manage system voltage.



# Voltage

Events in late 2021 and throughout 2022 have had two key impacts on voltage management costs. Increases in gas wholesale prices has had a significant impact on the default reactive power payment, made to providers of the obligatory reactive power service (ORPS). In the last 2 years, the rate has increased from ~£3/MVArh to ~£17/MVArh, increasing annual costs from ~£70m to ~£190m. Elsewhere, energy scarcity on the continent has driven increased interconnector exports, which has driven a greater level of self-dispatch on generators, reducing the synchronisation costs for voltage management, than would otherwise have been the case.

## Mandatory Reactive Utilisation




The Future Energy Scenarios 2022 (FES22) show that demand is expected to increase from 2027. This will mean greater power flows on the network, reducing the production of reactive power by transmission assets and therefore the reactive need. However, reactive demand continues to decline as covered by the last Operability Strategy report. The expected growth in electric vehicles, heat pumps and more embedded generation means the future trend is uncertain.

Operability Strategy Report / Reliable Network / 38

# Voltage

## What capability do we need to meet these changing operability challenges?



There are many parameters and criteria which we must adhere to when planning and operating the transmission system. At its core, we must maintain the network within strict voltage limits i.e. not exceeding the maximum or minimum voltage limit, and must not allow for the voltage level to rise or fall by more than a set percentage of the voltage level.

Reactive power capability mainly comes from two main sources; assets owned by transmission owners (TO) and transmission connected generation, providing both dynamic and static reactive services. Generators typically provide a dynamic service by adjusting the volume of reactive production or consumption in response to changes in the system voltage. TO assets provide static or dynamic services depending on the asset type; capacitors and reactors provide a static service whereby they are limited to 0MVAr or maximum, whereas static var compensators (SVC), mechanically switched capacitors (MSC) and static synchronous compensator (Statcom) are more flexible and are able to provide variable reactive power.

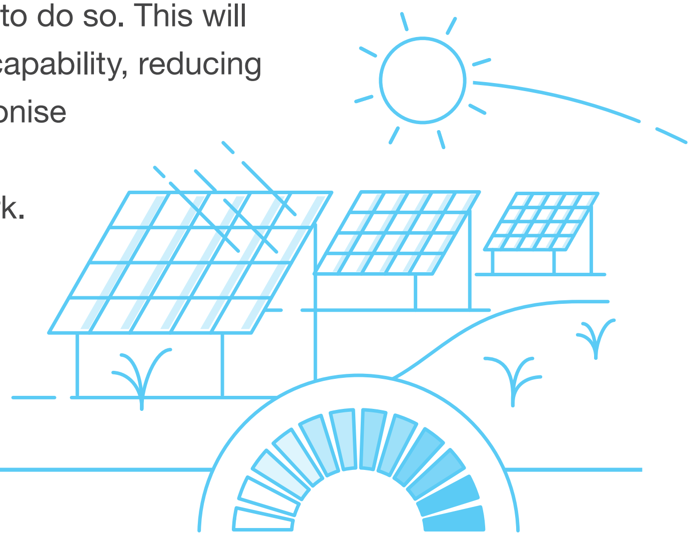
To meet the challenges of a more dynamic network with variable demand and more variable sources of generation there is likely to be a need to manage voltage more dynamically too. We will need more assets which can respond to fluctuations in voltage and smooth future variability.

FES22 suggests that Great Britain will be a net exporter of electricity by 2030 in all scenarios, with an installed capacity of at least 13GW of interconnection. When interconnector flows change, particularly when moving from export to import and vice versa, this impacts power flows across the rest of the network. In turn this will impact voltage levels with changing production or consumption of reactive power by network assets. With the potential for up to a 26GW change in interconnector flow, dynamic reactive capability will manage this more smoothly than static capability.

New interconnectors have obligations to provide dynamic reactive capability which will help to manage some of this uncertainty. Elsewhere on the network there is capability which already exists on the network which we don't necessarily have the means to access. Transmission connected generation are typically required to have a minimum reactive capability in accordance with the grid code. For power generating modules, such as wind, solar and battery storage, grid code only mandates reactive capability when the asset is generating at >20% of the asset's rated MW (this is also true for a battery which is consuming power). Having greater access to this capability will help voltage management and reduce the need to synchronise dispatchable generation at high cost.

Responses to the Request for Information (RFI) which we published in May 2022 shows that there is, and will be, generous volumes of reactive power capability at <20% of rated MW, and greater reactive ranges at all levels of MW output. We are exploring ways to access this capability for efficient voltage management.

In July 2022 we submitted a proposal (CM085) to modify the System Operator – Transmission Owner Code (STC) so that Offshore Transmission Owners (OFTO) will have to provide reactive power capability at <20% rated MW, where they have the capability to do so. This will increase available capability, reducing the need to synchronise generation in some areas of the network.



Operability Strategy Report / Reliable Network / 39

# Voltage

## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

Each year we publish a voltage screening report, which identifies regions which are or could face high voltage issues in the next 5-10 years. The 2022 voltage screening report provides a high level assessment of voltage needs, focussing on:

- Areas with a high dependency or reliance on limited assets or generation;
- Areas with high voltage management costs; and
- Network faults which could have led to voltages exceeding SQSS planning limits.

The screening report does not, however, indicate the actual reactive requirements or route to deliver solutions. We will be incorporating the screening report and assessment of future needs into future ETYS processes. The ongoing Network Planning Review will fundamentally transform how we undertake network planning. We are reviewing how we will communicate future system needs including voltage as part of the enduring Centralised Strategic Network Planning Process. The methodology for assessing these granular requirements has been further developed during 2022. We have used this methodology and worked with NGET to further assess and refine the residual reactive power requirements for 2025, which we published in last year's Operability Strategy report. The studies looked at overnight minimum demand periods during the summer months with low wind output. We are now using the methodology to assess reactive requirements from 2026-2030.

Operability Strategy Report / Reliable Network / 40

# Voltage

Whilst the residual requirement for 2025 has increased compared to last years view, we have investigated further the existing ability to meet these residual requirements. Most of these requirements can be met by synchronising dispatchable generation. However, we recognise the potential for significant consumer costs solving voltage needs using this mechanism. We are therefore developing other options which we will share in the near future, acknowledging the need for swift progress to deliver consumer savings from 2025 onwards.

In addition to needing reactive capability to meet the needs of the system, we also need to improve our forecasting capability of reactive power demands across the system. In our last report we touched on the declining trend in reactive power demand on the transmission system; one of the key factors in the increasing reactive requirements. This declining trend began around 2005 and has resulted in reactive power being injected onto the transmission system instead of being absorbed by the distribution system. Whilst we understand some of the reasons for this decline, we do not have a view when this declining trend will stop. We are developing an innovation project to investigate the drivers behind the trend and develop forecasting methods and tools for the future.

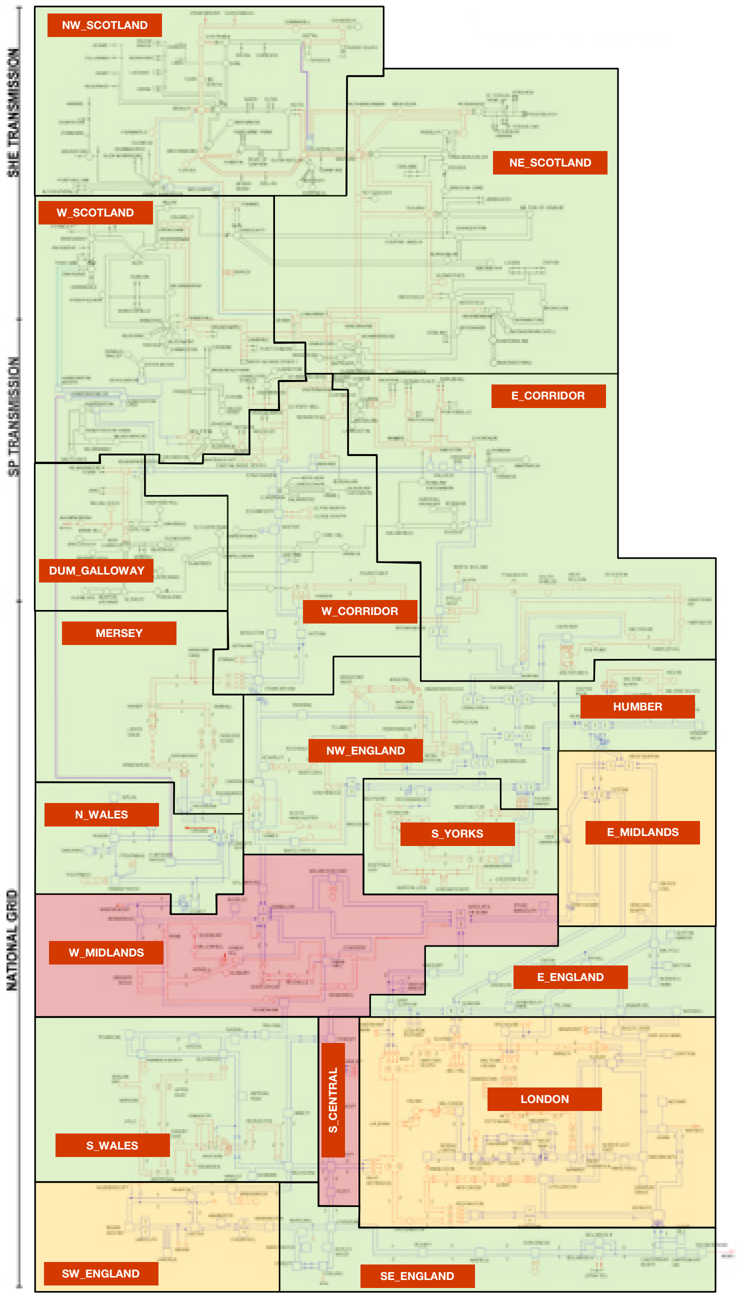
| Region | 2025 MVAr need OSR 2022 (residual requirement) | 2025 MVAr need OSR 2023 (residual requirement) |
|---|---|---|
| LONDON | 300MVAr | 500MVAr |
| W_MIDLANDS | 300MVAr | 600MVAr |
| S_WALES and S_CENTRAL | 600MVAr | 700MVAr |
| SW_ENGLAND | 200MVAr | 125MVAr |
| E_ENGLAND | 200MVAr | 300MVAr |


Operability Strategy Report / Reliable Network / 41

# Voltage

Despite the challenges faced, we are still driving towards meeting our zero carbon operation in 2025 ambition. As in previous Operability Strategy reports, we have provided a map showing which voltage regions could be managed using zero carbon solutions. Key changes since last year are:

- **North East Scotland –** this region can now be managed almost always using zero carbon solutions
- **North Wales –** this region can now be managed almost always using zero carbon solutions
- **South Wales –** new connections in the region reduce the reliance on fossil fuelled generation
- **South West England –** many system conditions lead to a need to run fossil fuelled generation
- **West Midlands –** expected investment and new connections could mean zero carbon operation from 2026
- **East England –** should be manageable with zero carbon options by 2025




## GB existing transmission system

### Legend

- 400kV Circuit
- 275kV Circuit
- 220kV Circuit
- 132kV Circuit
- HVDC Circuit
- 400kV Substation
- 275kV Substation
- 132kV Substation

Green represents regions which can largely be operated at zero carbon, amber represents regions which can be operated at zero carbon under certain scenarios, and red represents regions which cannot be operated at zero carbon.

Top Middle Bottom Click to expand

Operability Strategy Report / Reliable Network / 42

# Voltage

## How do requirements change under differing Future Energy Scenarios?

- As we have discussed, reactive requirements are localised, and are driven by many factors including demand, generation and system conditions. Across the scenarios we expect the need for reactive services to increase.
- During summer minimum periods voltages are raised due to reduced power flows across the network, cables which are in service, and there is a reduced ability to take circuits out of service to help with voltage control.
- During winter, periods of high demand coupled with high renewable output lead to increased power flows. We need to ensure that the system is secure for faults which could otherwise lead to low voltages outside of SQSS limits.
- Increasing interconnection will lead to higher flows on the system, particularly during exports. When interconnector flows switch between import and export, this can stress network assets and result in high volts swapping to low volts. Leading the Way has significantly more interconnector capacity by 2030 than the other scenarios.
- The market dispatch of fossil fuel generation differs greatly between the Falling Short and Leading the Way scenarios. Whilst this doesn't affect our ability to maintain a compliant network, it will have a significant impact on consumer costs. We are progressing ways to mitigate these costs.

## What is the next big operational challenge?

Less dispatchable generation and generation moving to different areas are removing the provision of dynamic reactive power from key locations across the network. In many regions where asynchronous generation is replacing dispatchable generation, there is sufficient reactive power capability to maintain voltages within limits. However, where overall growth in GB asynchronous generation is displacing reactive power provision in other regions, we must source new zero carbon solutions.

Loss of access to this dynamic reactive power capability will make voltage management more challenging, more costly or both. We need to ensure there is sufficient dynamic capability available in the right locations to manage the future variability in network flows, demand and generation.

Operability Strategy Report / Reliable Network / 43

# Thermal

ESO

# Thermal

## Summary

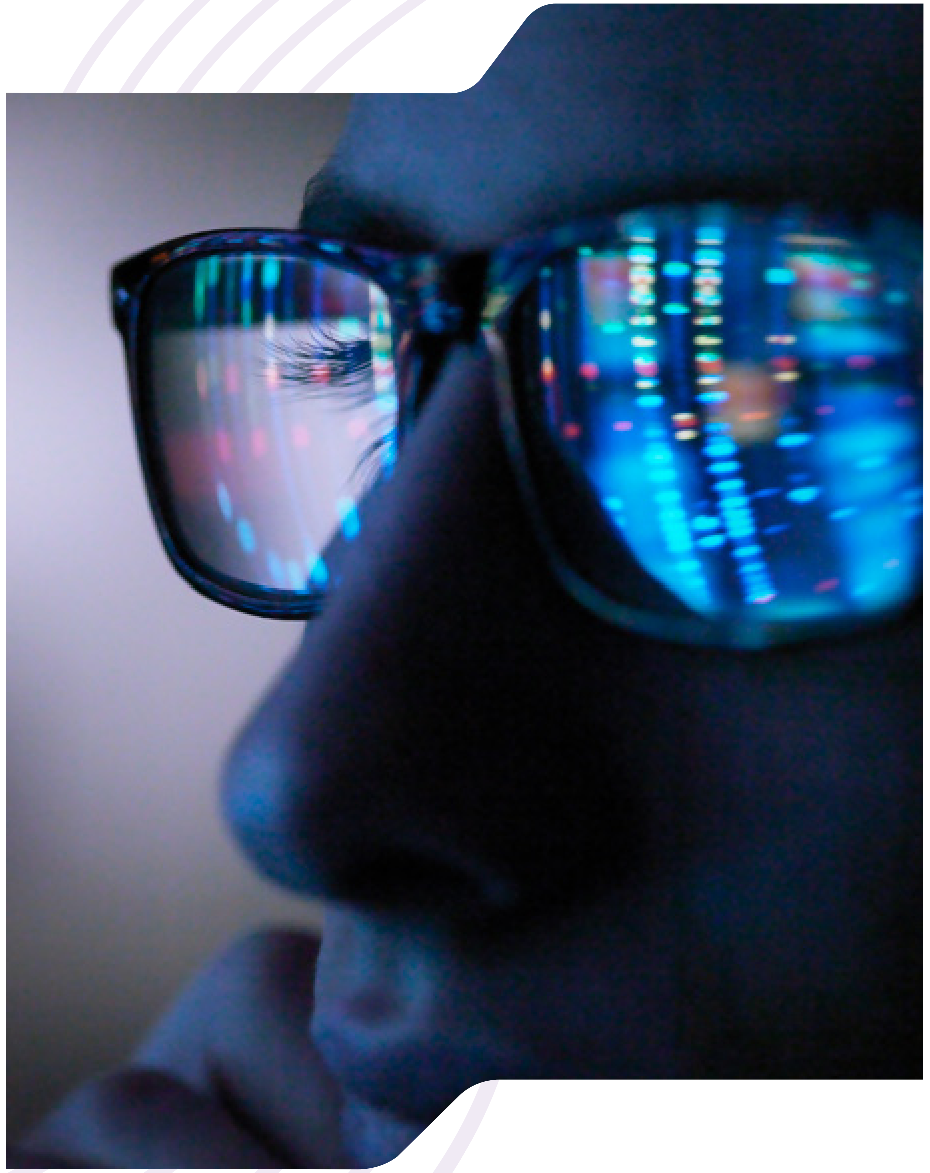
The ambition to operate a zero carbon network in 2035 and enable net zero by 2050 requires significant investment in the transmission network to accommodate more asynchronous generation, generation moving to different areas and changing sources of demand. In July 2022 we published our first Holistic Network Design alongside a refreshed Network Options Assessment. Together they recommend 94 asset investments to deliver a network which can accommodate the Government's ambition of 50GW offshore wind by 2030.

The Future Energy Scenarios indicates the need for a demand side strategy to avoid wasting renewable energy. Incentivising new demand to connect in the right locations can help effectively alleviate constraint costs. We are working on two innovation projects to demonstrate how green hydrogen can support constraint management, and develop a probabilistic model which quantifies the risk of energy flow congestion.

As part of our Net Zero Market Reform programme, we have stated that introducing dynamic locational signals via nodal pricing could offer a solution to addressing thermal constraints. BEIS is considering nodal pricing as one of several options to improve locational signals in its Review of Electricity Market Arrangements (REMA). Alongside market reform, there are significant challenges with network capacity and connections which could hinder solutions or investment.

## What do we mean by thermal?

**The transmission network has limited capacity to transport power. The thermal workstream covers how we manage this capacity.**



Operability Strategy Report / Reliable Network / 45

# Thermal

## What are our obligations and what are the future operability challenges?

### Obligations

As the Electricity System Operator, it is our responsibility to identify the future transmission network needs as we drive towards operating a zero carbon electricity system, and enable the transition to net zero. Planning the future transmission network starts with the Future Energy Scenarios (FES). These scenarios indicate how energy could be produced and consumed. We use these scenarios to determine generation capacity, peak demand and transmission network power flows. We can then identify where additional network capacity is needed and this is published in our Electricity Ten Year Statement (ETYS).

Stakeholders are then invited to propose solutions which could meet these requirements, and we assess these in our annual Network Options Assessment (NOA). The NOA makes recommendations for the most economic and efficient solutions to proceed, and others to hold or stop. These recommendations are often for new network build or to reinforce existing network but can also be for commercial solutions.

Where network capacity is not sufficient to transfer the flow of energy generated, the ESO must resolve the boundary constraint by reducing the output of (constrain) generation behind the constraint. As we move towards a net zero future, more generation must connect to the electricity network. Careful management of where this generation connects is required, or appropriate processes in place to plan a network fit for the future. If not, significant costs will be incurred constraining low and zero carbon generation because there isn't sufficient network capacity. Often, these costs are incurred as the ability to connect new generation occurs at a pace greater than delivery of new infrastructure. Therefore, future network planning will likely require a move to more strategic and anticipatory investment.

It is also important that we make sure there are markets in place which support flexibility in operational timescales. A local constraint market (LCM) will be delivered in early 2023 to help address the high cost on managing thermal constraints on the B6 boundary, focusing on generation turn-down and demand turn-up from new providers of flexibility in Scotland. The LCM is intended to be an interim solution before Regional Development Programmes can be delivered in Scotland. The LCM will help to inform our thinking on local markets.


Operability Strategy Report / Reliable Network / 46

# Thermal

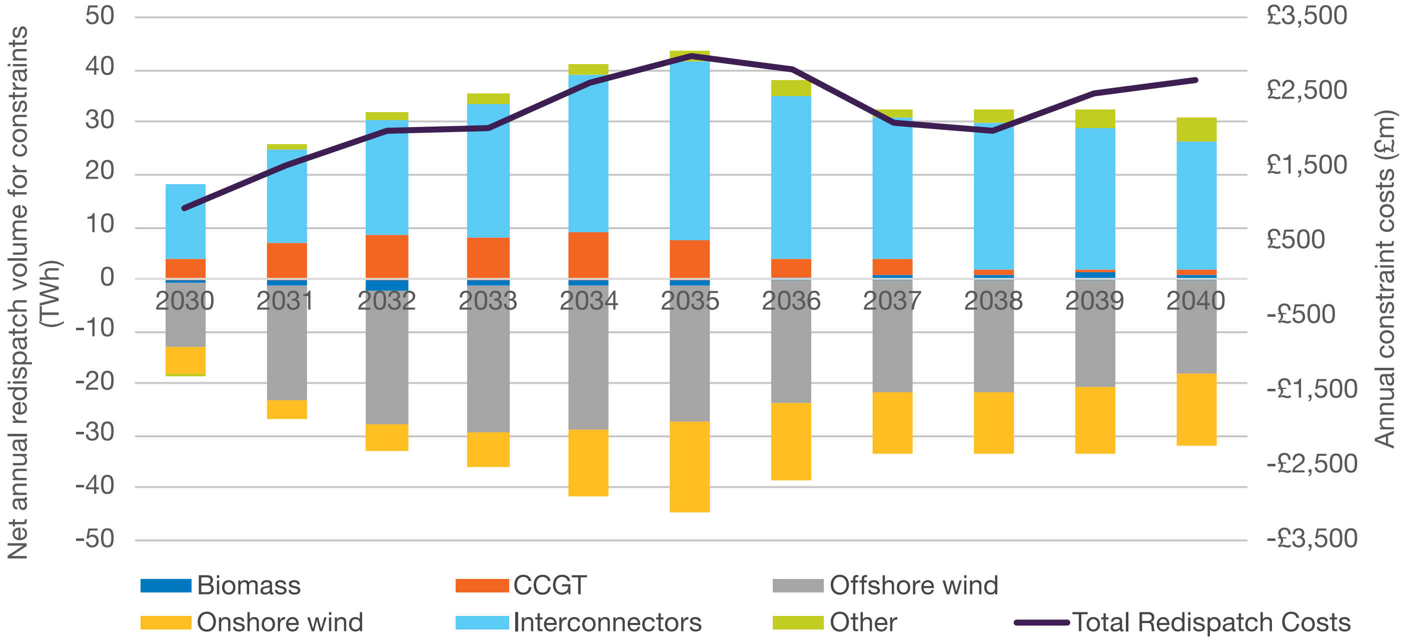
## Future challenges

There are many challenges to overcome to enable the transition to a carbon free network by 2035 and net zero by 2050. The Future Energy Scenarios show that demand for energy will increase with the electrification of transport, heat and industrial processes. Generation is moving to different areas, requiring network investment/reinforcement. Network planning is needed now to meet the network needs out to 2050. Earlier this year, we published the Pathway to 2030 Holistic Network Design, which sets out network needs to enable 23GW of offshore wind to connect by 2030. We are also conducting our own review into network planning (NPR) and are engaging with the BEIS and Ofgem network reviews.

As covered in previous editions of this report, the thermal challenges we experience are generally a cost issue, rather than security related. Annual transmission costs have increased ten times since 2010 and are expected to continue to rise. Whilst FES22 predicts at least 15TWh of curtailed energy by 2030 in the net zero scenarios, this is due to excess generation. There will still be a need to constrain considerable volumes of generation for constraints. We must find ways to reduce these constraint costs, whilst enabling much of this new generation to connect and consumers to benefit from zero carbon generation.

Turning down generation for constraints requires the energy to be replaced elsewhere on the network, and this is typically done by increasing generation on dispatchable generation. But by 2035, unabated fossil fuel generation will only be for security of supply, so we must find other ways to balance the energy when managing constraints. NOA modelling indicates that much of the energy balancing from 2030 will be on interconnectors. We published a paper on the modelled constraints in August 2022.

### NOA7+HND redispatch for constraints




In all the future energy scenarios, GB is a net exporter of electricity by 2030. This requires us to plan and operate the network to transfer power from generation to interconnector locations. Most of these are in the South of England, and we experienced in July 2022 the impact of a network which struggled with the demand for exports. Interconnector flows are driven by the spread between wholesale prices in different countries or zones, typically flowing from the zone with lower prices to the zone with higher prices. In July, energy scarcity intensified on the continent, resulting in exports on all South East interconnectors. Expensive actions were required on the interconnectors at £9500/MWh to resolve constraints. The GB wholesale price does not reflect locational signals which can lead to interconnector flows exacerbating constraints. Clearly, it is not sustainable to operate the network with prices like this in future.


Operability Strategy Report / Reliable Network / 47

# Thermal

## What capability do we need to meet these changing operability challenges?

### Network capacity

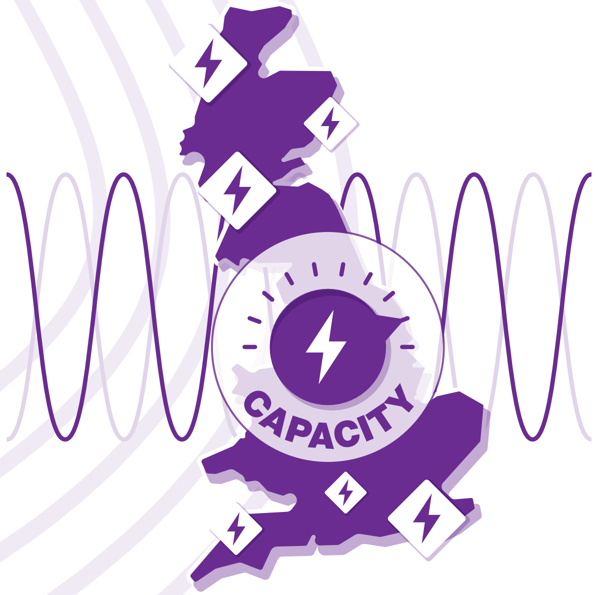
The existing processes for assessing network capacity and identifying economic solutions are well defined. The Future Energy Scenarios indicate how energy could be produced and consumed. This informs the assessment of network capability in the Electricity Ten Year Statement. The Network Options Assessment then recommends which economic solutions should be progressed.

The existing process assumes a generation and demand background evolving under the existing single national wholesale market price, where the Transmission Network Use of System (TNUoS) charge provides the locational signals for investment. If market arrangements were to change as a result of the Review of Electricity Market Arrangements (REMA), there could be stronger locational signals for new investment. This could alter aspects of our NPR, BEIS' OTNR and Ofgem's ETNPR and the wider Centralised Strategic Network Plan (CSNP).

In April 2022, the UK Government published the British Energy Security Strategy with an ambition for 50GW of offshore wind to be connected to the GB network by 2030. In July 2022 we published recommendations for network investment which would facilitate the connection of this volume of offshore wind. The HND project and NOA refresh have identified 94 schemes, at a cost of £22bn, that are required to enable the Government's ambition for 50GW of offshore wind by 2030.

Not only do we need network capacity to transfer power from generation to consumption, but we also need capacity which allows for connection of generation and new forms of large scale demand on the transmission network. Enabling the connection of renewable generation and flexible demand is key to reaching a zero carbon network in 2035 and net zero in 2050. We are working with stakeholders to achieve an improved connections process, in both the short and long term. In October 2022, we opened an amnesty for transmission entry capacity, offering industry the opportunity to terminate connection agreements and free up connection capacity.

Across the network we are seeing changes in the connection landscape. There are changes in demand at interface points; an example being the metro in South Wales. Areas of the network are struggling for capacity due to the significant volume of generation wanting to connect; for example, East Anglia. We are also learning to manage the connection of large scale modern technology demand which can operate 24/7. This uses up a lot of demand capacity and can cause difficulty for DNOs wanting to connect more domestic demand.




Operability Strategy Report / Reliable Network / 48

# Thermal



## Constraint management

Beyond network investment, constraint costs are typically managed by turning down generation to reduce the transfer of power across the affected boundary. Generation is then increased on the other side of the boundary to balance the energy. The future of constraint management needs to consider demand flexibility, particularly from large flexible demand such as data centres and electrolysis.

FES22 considers the need for a demand side strategy to efficiently balance renewable generation with demand and reduce reliance on unabated fossil fuel generation. This demand side strategy is required to ensure that during periods of high renewable generation, energy isn't wasted due to oversupply. In the context of constraint management, effective incentives to increase demand from large flexible demand during periods of oversupply and active network constraints would mitigate the need to curtail and constrain renewable energy. In the short term, we are introducing stronger market signals through projects such as the Local Constraint Market but believe that in the longer term the introduction of stronger locational signals would be beneficial, as set out in our Net Zero Market Reform programme.

We are working with industry partners to understand the capability of large flexible demand and what market signals are required to take advantage of demand flexibility to produce green products, such as green hydrogen. The ESO's Markets Roadmap, due in March 2023, will disseminate the findings from an upcoming innovation project seeking to understand the technical and commercial models of a range of service providers, including large flexible demand units. Where appropriate, this publication will consider how the ESO's markets can be designed to provide optimal signals to harness this flexibility. An innovation project aims to demonstrate the benefits of green hydrogen to support network constraints.

We are also progressing an innovation project which aims to develop probabilistic forecasts of power flows to reduce the uncertainty resulting from variable sources of generation. When managing network constraints, less power is allowed to flow across the boundary than the rated capacity. This is to allow for the loss of circuits/assets which reduces the boundary capacity. Part of this reduced power flow is also to account for uncertainty in energy forecasts. Reducing the uncertainty around variable sources of generation will result in increased power flows and reduced constraint costs.

Operability Strategy Report / Reliable Network / 49

# Thermal



## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

In last year's Operability Strategy report we highlighted that constraint costs are expected to rise out to 2030 and the delivery of large NOA recommended network investment may by delayed ahead of mitigating much of these costs. We are working with Ofgem to help the accelerated delivery of strategic transmission investment. This would help ensure a large proportion of these projects will be delivered in time for 2030. In the meantime, we are progressing further ways to mitigate some of these costs ahead of network investment.

We have delivered a second tender round of the Constraint Management pathfinder, for the B6 boundary intertrip service. We have developed another constraint management intertrip service for East Anglia to help manage the significant volume of offshore wind connecting in the region.

We are continuing to work with TOs to identify enhanced services such as dynamic line ratings, HVDC run back schemes and new ways of working regarding post fault actions to provide increased constraint limits.

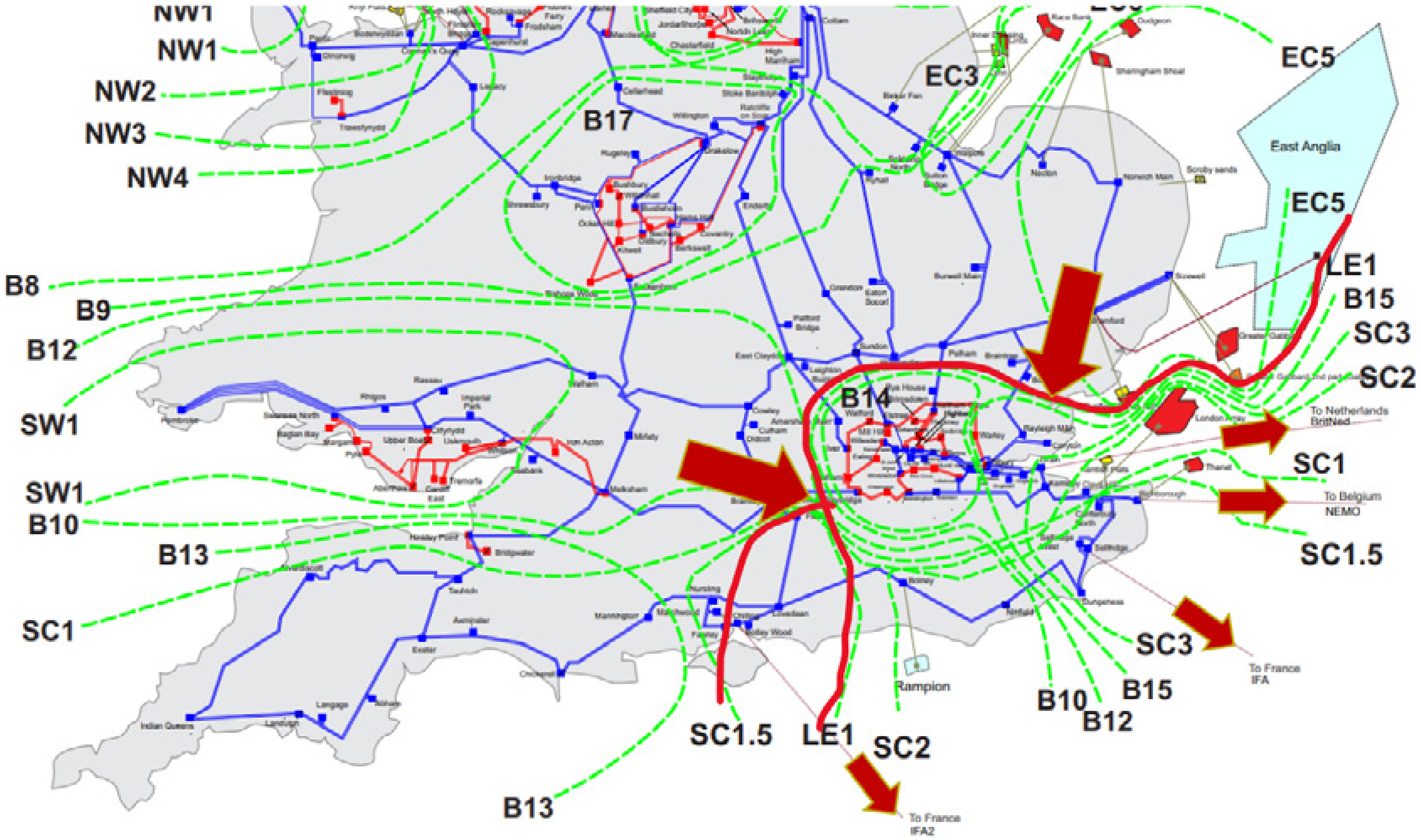
We are working with stakeholders and innovation projects to better understand the capability of large scale demand and how it can deliver benefits for constraint management. This would be both for increased demand to reduce the need to constrain renewable generation, but also for decreased demand to avoid turning up fossil fuelled generation or high price actions on interconnectors.

Across all Future Energy Scenarios 2022, we will be a net exporter of electricity by 2030. In July 2022, we experienced the effects of a network which did not have the available capacity to allow for high demand and full exports on interconnectors in the South East. Power markets on the continent and impacts of the war in Ukraine led to GB gas being traded at significant discount to the continent. This resulted in exports on all South East interconnectors. Combined with demand in London, this drove significant power flows across the LE1 and SC boundaries. We have worked with NGET to increase the LE1 boundary to the highest it's ever been. However, planned and unplanned outages had reduced the capacity of these boundaries.

With all available generation in the South East running, trades were required on interconnectors to reduce the power flow in to the South East. The generation scarcity on the continent, and alert states by European TSOs, drove the extreme prices (~£9500/MWh) to reduce interconnector exports. We need to find ways to manage the network in future which doesn't expose the consumer to extreme prices and costs. Reflecting network congestion in the wholesale price is likely to have mitigated this event by reducing incentives for the interconnectors to export and demand to be connected at the periods with highest costs.

Operability Strategy Report / Reliable Network / 50

# Thermal



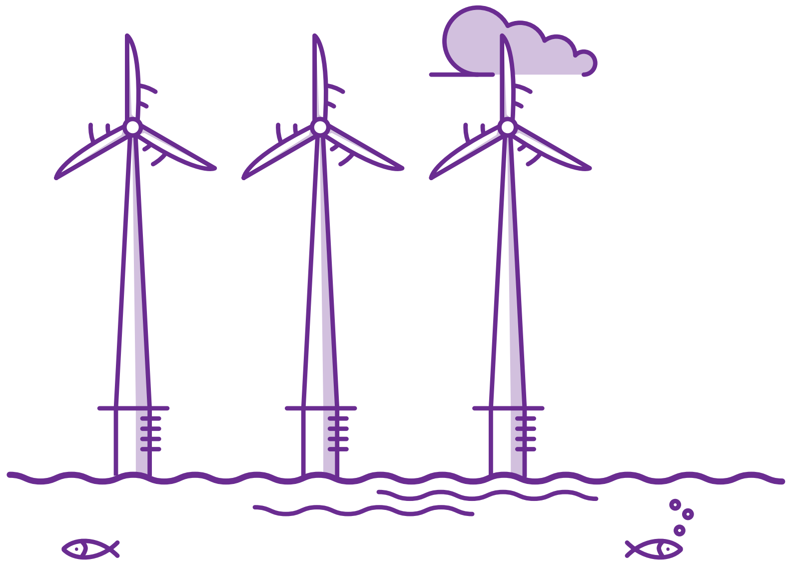

The Pathway to 2030 HND and NOA 2021/22 refresh make recommendations to proceed with 94 asset-based options, delivered by 2030. Of these, 56 projects are required for a compliant network against the design rules. However, Government support is required to enable accelerated delivery of 11 of these projects due to existing regulatory and consenting processes. A further 38 projects are optimal for delivery before 2030 to significantly reduce constraint costs. It is clear that significant investment and support from Government is required to reach the BESS ambition of 50GW offshore wind by 2030.

Operability Strategy Report / Reliable Network / 51

## How do requirements change under differing Future Energy Scenarios?

The different Future Energy scenarios generally share a common narrative. The energy transition will increase power flows from North to South and from offshore generation to inland. Network investment is required to accommodate this transition but the pace at which the change happens differs.

The FES22 indicates that 50GW offshore wind could be as early as 2030 under Leading the Way, or as late as 2040 under Falling Short. In the Leading the Way scenario, there is 42GW of solar generation in 2030 and 70GW in 2040.



## What is the next big operational challenge?

As we've seen throughout this chapter, much of the future operational challenges come from the scale and pace at which generation and demand grow. This growth is needed to meet the ambitions for a zero carbon electricity network by 2035 and net zero by 2050. Enabling growth in network investment, increased capacity for new connections and new tools for constraint management all form part of meeting this big operational challenge.

We are progressing our Network Planning Review to inform Ofgem's Electricity Transmission Network Planning Review and the development of a Centralised Strategic Network Plan. We are continuing to develop the Holistic Network Design process, sharing recommendations with developers in Q1 2023 and publishing the second HND later in 2023.

Considerable constraint costs are expected throughout the rest of the decade. These are largely resulting from considerable renewable generation connecting to a network which currently cannot accommodate the volume of power and transfer it to the point of demand. Point of demand will also become less well defined as we move to a world with large scale demand connecting across the transmission and distribution networks. Potential market incentives need to align with these constraint costs and mitigate their increase.

Operability Strategy Report / Reliable Network / 52

# Restoration

ESO

# Restoration

## Summary

The key change to our requirement for restoration capability between now and 2030 is the introduction of the Electricity System Restoration Standard (ESRS). This provides an industry agreed standard which will drive changes to services, codes and network solutions required. We are working with industry through a series of working groups established through Grid Code change GC0156 to establish the specific changes required.

Meanwhile decarbonisation of the electricity system means we will continue to look at ways to diversify our portfolio of services through the Distributed Restart project and competitive procurement exercises.

## What do we mean by Restoration?

**In the unlikely event that the lights go out, the ESO has a robust plan to restore power to the country as quickly as possible.**

Operability Strategy Report / Reliable Network / 54

# Restoration

## What are our obligations and what are the future operability challenges?

System restoration has historically been highly dependent on large, dispatchable generation. As the UK moves to cleaner, greener and more decentralised energy, new options must be developed. The enormous growth in asynchronous generation, presents an opportunity to develop a radically different approach to system restoration. The greater diversity in the provision of restoration services and our reduced reliance on traditional sources, will improve resilience and increase competition leading to reductions in both cost and carbon emissions.

The Electricity System Restoration Standard (ESRS) was introduced through a policy statement from BEIS in April 2021, highlighting the need to introduce a legally binding target for the restoration of electricity supplies in the event of a National Electricity Transmission System (NETS) failure. This was followed with a consultation from Ofgem to modify the ESO licence to provide the framework by which this standard can be implemented. It requires us to:

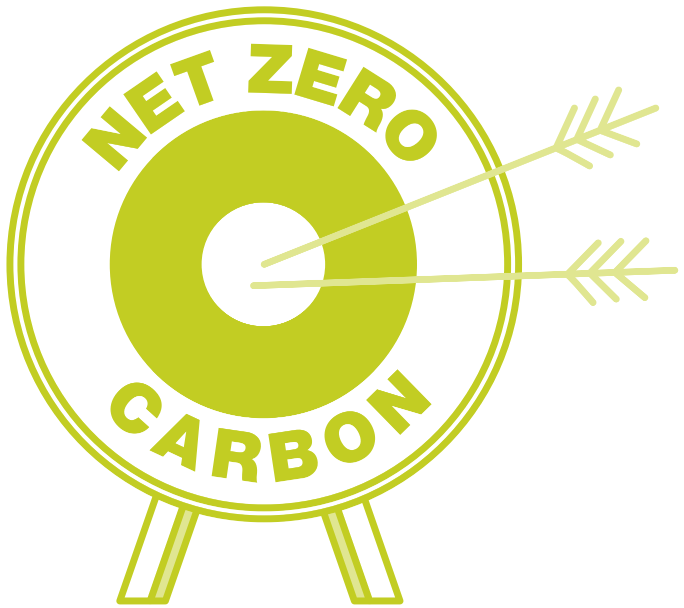
a) ensure and maintain an electricity restoration capability; and

b) ensure and maintain the restoration timeframe.

The timeframe set out within our licence is set at:

- 60% of electricity demand being restored within 24 hours in all regions; and
- 100% of electricity demand being restored within 5 days nationally

To meet this requirement and ensure restoration services can support our ambition for zero carbon operation of the system by 2025, we are currently proposing a number of changes to all relevant codes, such as the Grid Code, CUSC, STC and Distribution Codes, to facilitate the direction from BEIS and standards set out in our licence. There are also significant technical, organisational and commercial challenges to address to ensure these diversified sources of restoration can be implemented effectively. These are being addressed through GC0156.




Operability Strategy Report / Reliable Network / 55

## What capability do we need to meet these changing operability challenges?

Restoration services have traditionally been procured bilaterally from large dispatchable generation. In June 2022 we released a tender for the South East region which was the first of its kind to include learnings from the Distributed ReStart project, to enable the potential participation of distribution led restoration, as well as transmission led solutions. These solutions will be available for delivery from July 2025. In October 2022, we also launched a tender for the Northern region, for service go live in November 2025.

In addition, we released a nationwide, wind-only tender in August 2022 to prove the feasibility of getting both onshore and offshore wind energy supplying restoration capability at full service (i.e. the same technical requirements as traditional transmission-led generators). More detail on all of these tenders can be found on our website.

The Distributed Restart project explored how asynchronous generation could be used to provide restoration services, from diverse technologies across Great Britain. The aim of the project was to demonstrate a bottom-up approach to restoration by utilising distribution level resources through to transmission level to restore the system. We are now in the process of moving from Innovation to BAU by using learnings from this project to supplement existing providers of restoration services and increase both our flexibility and resilience when procuring restoration services for the future.

A key challenge for all future restoration services is ensuring that engineering solutions, organisational coordination and commercial and regulatory frameworks can all work together to ensure resilience and flexibility in the operation of the network. We need to ensure that all providers have the required capabilities to ensure effective and efficient system restoration in the event of a partial or total shutdown of the network.

Operability Strategy Report / Reliable Network / 56

# Restoration

## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

Grid Code modification GC0156 (implementation of the Electricity System Restoration Standard) has been established to clarify the requirements on CUSC parties, Restoration Service Providers (RSPs) and Distribution Network (DNO) taking part in restoration activities of their obligations so that we can satisfy our new licence obligation. It was originally organised into seven working groups, focusing on the different requirements needed to ensure effective and coordinated restoration of the system. However, since the establishment of GC0156, only four of the seven workgroups have been progressed further. These four workstreams are detailed here whilst the outputs from the other three working groups have also been considered in the overall ESRS solutions.

- **Future networks:** identifies the development needs of the networks to accommodate changes in the generation mix across GB to implement ESRS. This could be the level of connected generation required (during different time periods i.e. peak demand) as well as the time required by different generation to synchronise. This workstream also looks at the requirements for DNOs such as their network design and resilience as well as different options for restoration zones.
- **Markets and funding:** the aim of this workstream was to understand how we can further remove market barriers (real or perceived) and assist in the development of agile solutions for restoration. It establishes the key procurement principles that we will adhere to during the development and delivery of competitive procurement tenders. Whilst significant changes have been implemented to broaden participation and reduce barriers to entry, (such as introducing competitive procurement events), the process for achieving restoration has historically been developed on the basis of a top-down restoration strategy. We are therefore using learnings from the Distributed Restart project to deliver new commercial frameworks and procurement mechanisms to access Restoration services from DER utilising a bottom-up approach, rather than a top-down.
- **Assurance framework:** this defines the assurance activities that should be progressed across the industry for restoration. This also includes resilience of network plant, relevant checks on services (including restoration tests), and training for engineers.
- **Communication infrastructure:** provides the high-level requirements for communication infrastructure, focusing on themes such as band width of communications and any upgrades required, inter-control centre comms and cyber security. The Distributed Restart project has created a functional specification for resilient & cyber secure comms for DER/DNO interfaces.

Compliance with the ESRS is required by 31 December 2026. BEIS expect that any code changes should be in place by September 2023.


Operability Strategy Report / Reliable Network / 57

## How do requirements change under differing Future Energy Scenarios?

Each of the FES scenarios assume a different generation mix with varying levels of asynchronous generation across each scenario. All scenarios, however, assume a greater level of asynchronous generation on the system than is currently the case meaning we will need to ensure we can use all available technologies for future restoration. The ESRS is aiming to ensure at least three technologies per DNO licensed area to allow for redundancy.

In addition, peak demands increasing in the future mean that greater amounts of generation will be needed to achieve this level of restoration. By 2030 the lowest predicted average cold spell (ACS) Peak System Demand will be 62.7GW (Leading the Way), compared to 58GW in 2020. With more variable sources of generation, more generating units will need to be included in the restoration to achieve the same electrical energy output.

## What is the next big operational challenge?

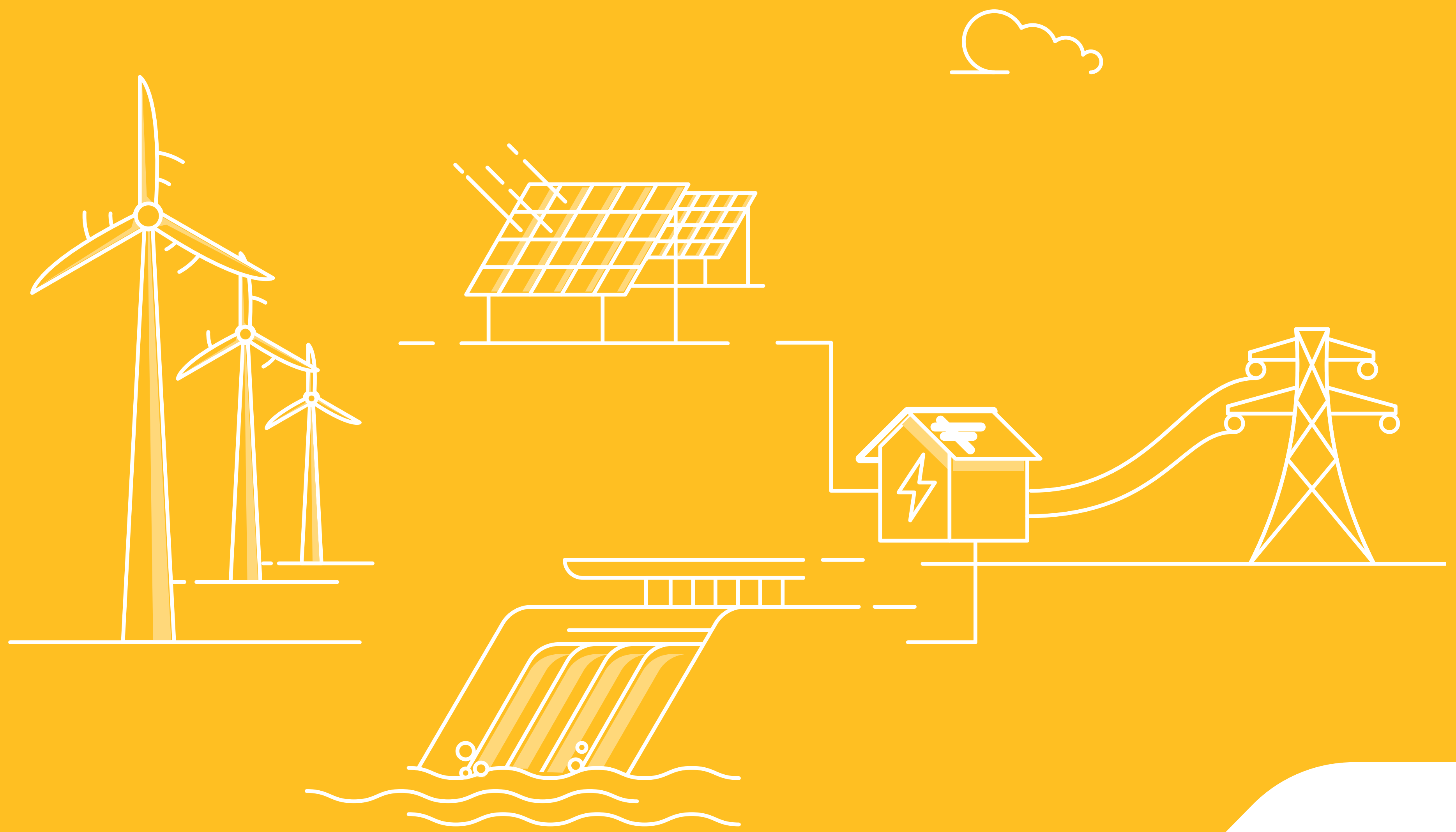
Currently, the System Operator - Transmission Owner Code (STC) 'Black Start' procedure does not recognise offshore networks as contributing to Restoration. With the future growth for offshore wind targets set at 50GW by 2030, it is likely that the bulk of generation in future will come from offshore sources. A fundamental part of the ESRS is exploring the need to integrate offshore networks into the solution, this is being considered as part of the Regulatory Frameworks workgroup under GC0156. It will reflect the necessary changes required to the STC.

The Offshore Transmission regime was first introduced in 2009, based at the time largely on radial connections where offshore transmission was classified as any offshore circuit operating at 132kV and above. When the technical requirements for offshore networks were developed, it was not appropriate to specify a wider reactive capability at the offshore Grid Entry Point as the effect of the cable gain would have limited benefit to the onshore system (although there is scope for a wider reactive capability range when agreed between the OFTO, Generator and ESO). Therefore, specific requirements for reactive capability were introduced at the Transmission Interface Point.

Going forward many of the offshore networks are likely to be meshed HVDC networks and complex in their configuration and design. Therefore, and as part of the design stage of the offshore coordination project, consideration will need to be given to Restoration as part of the wider Offshore Network and Holistic Network Design work.

Operability Strategy Report / Reliable Network / 58

# Balancing the System



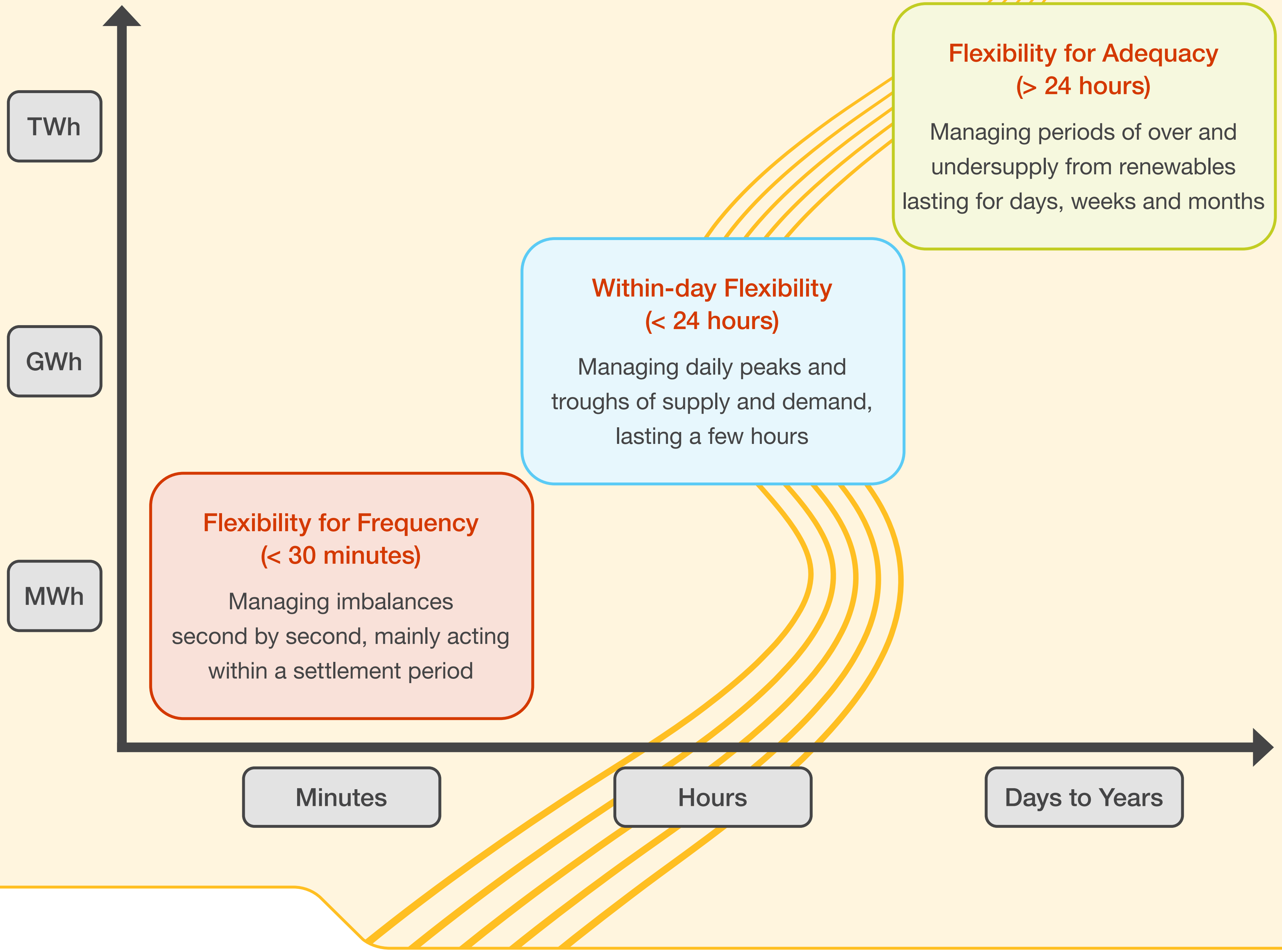
ESO

# Energy balancing over different time scales



## One of the most fundamental requirements of an electricity system is that supply and demand are always balanced.

The wholesale market currently provides the majority of system balancing during the day, with the ESO performing the residual balancing and balancing on a second-by-second basis. For us to achieve this energy balancing we need flexibility, in both supply and demand, adjusting both sides to ensure they always match. The Frequency, Within-Day Flexibility and Adequacy workstreams all share this core objective, but each focuses on a different timescale. The Frequency workstream is the most mature of the three; as the system moves towards zero carbon operation, the system need will start to include longer durations and larger volumes of energy imbalance. We set the boundaries between these three categories of flexibility at 30 minutes and 24 hours, although there will be some overlaps and gaps at the boundaries.

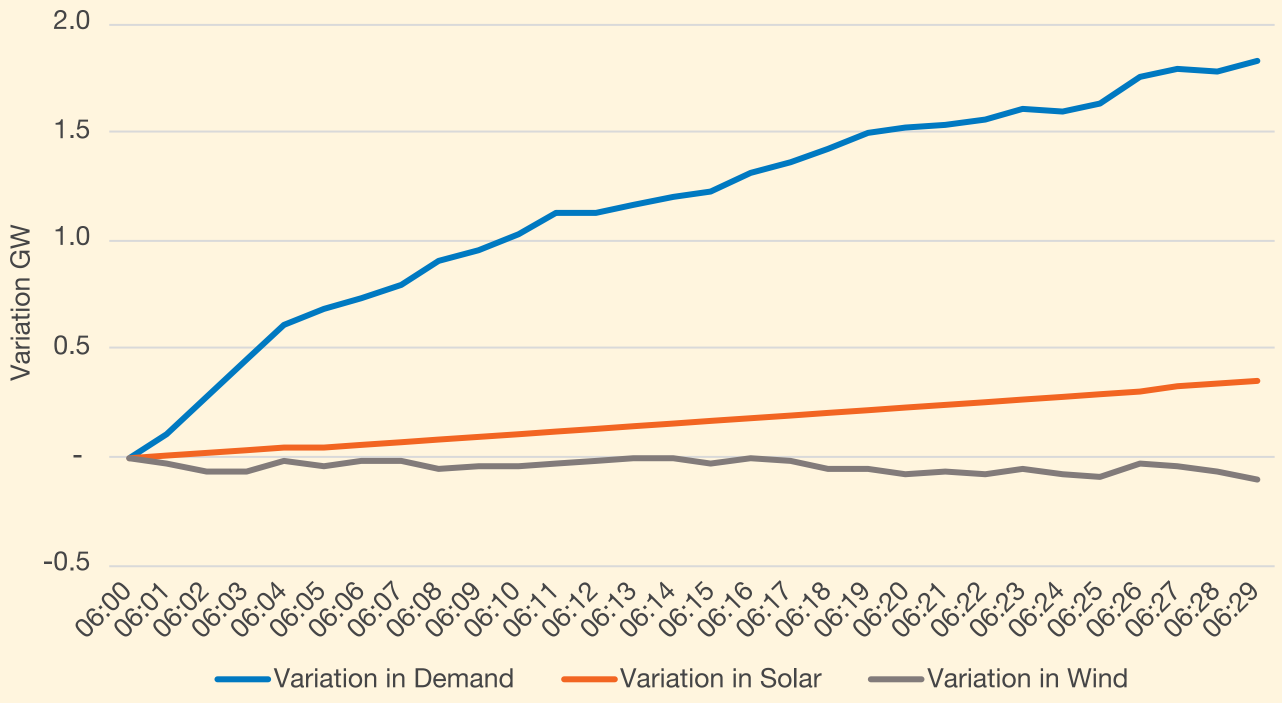



Operability Strategy Report / Balancing the System / 60

# Energy balancing over different time scales



**Variation in wind generation, solar generation and demand over a settlement period (06:00-06:30 16/08/21)**




Half hour Day Year

The energy imbalances in the electricity system are driven by differences between variable supply and variable demand. Within a settlement period these imbalances are caused by variations in supply and demand, over seconds and minutes, caused by faults, forecast errors and other unexpected changes. Within-day, the imbalances are mainly caused by variable sources of generation and demand (e.g. cooking and lighting) changing with daily human behaviour. Over longer periods the imbalances are mainly caused by changes in wind generation, driven by weather patterns that can last for days, weeks and months, and by seasonal changes in demand for heat.

Energy balancing, over all three timescales, is usually thought of as a system-wide need, which can be met with non-locational solutions. However, there are interactions between this system-wide need for energy and the location specific needs covered in the Reliable Network section. For example, an action taken for energy balancing reasons might increase the supply in one area, with impacts on thermal constraints, voltage and short circuit levels in that area.

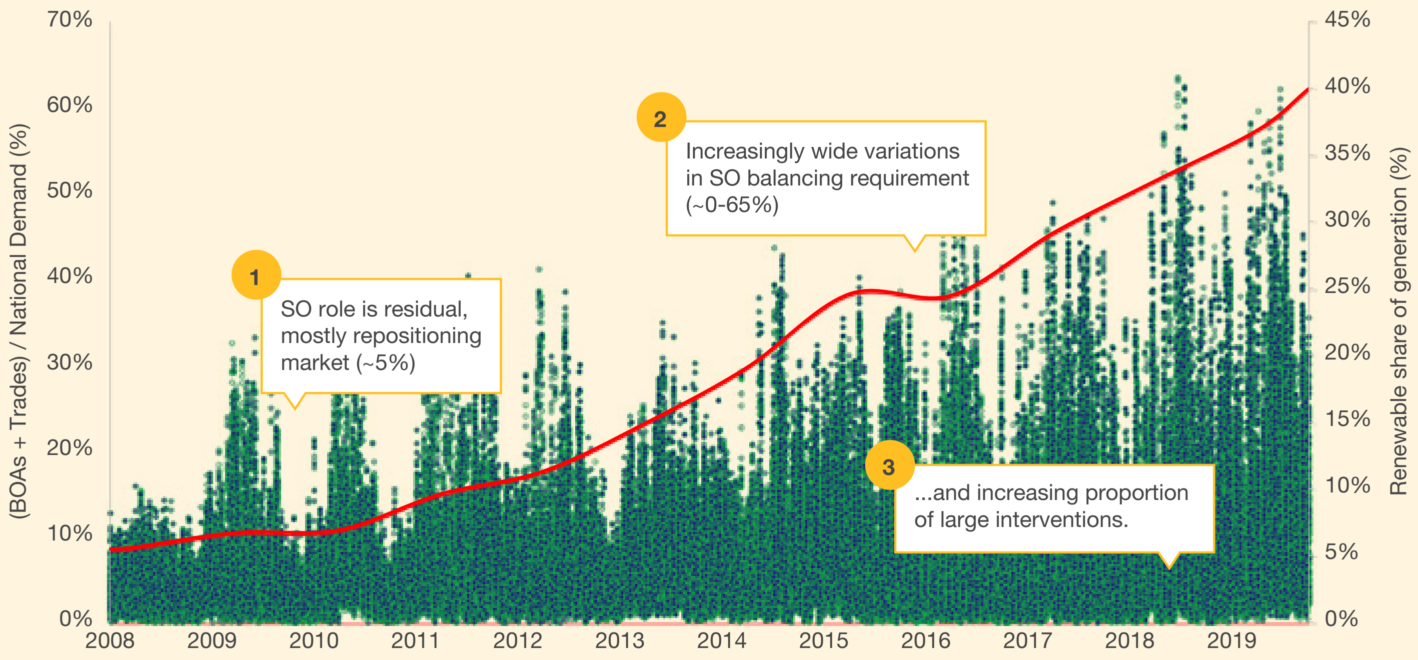
Therefore, we need some locational information, even for non-locational services. In the future, as we operate the system with lower inertia levels, the locational aspects of energy balancing may get more important.

Energy balancing is currently mostly delivered by markets, with some interventions by the ESO at all three timescales. Energy balancing within a settlement period is delivered by the ESO, mainly using frequency products, sold on liquid, day-ahead markets. Energy balancing within-day is mainly delivered by wholesale electricity markets, with multiple buyers and sellers, volumes of supply and demand leading to a price, and the price then influencing supply and demand. The ESO also intervenes when necessary to ensure that balancing is achieved at an efficient cost. The ESO also intervenes when necessary to ensure that balancing is achieved at an efficient cost. Energy balancing over longer time periods, to ensure supply adequacy, is currently achieved through a mixture of wholesale energy markets and the Capacity Market. The amount the ESO has to intervene to balance the system has been increasing over time.

Operability Strategy Report / Balancing the System / 61

# Energy balancing over different time scales

ESO trades and instructions as a share of national demand (2008-2019)




In the future, we want energy balancing to continue to be mainly delivered by price signals and markets, with the ESO acting as a "residual balancer". We expect energy balancing within settlement periods to work very similarly to how it does today, with a suite of frequency products designed for the future system needs. In a future operating model with a centrally dispatched wholesale market, there might also be co-optimised procurement of energy balancing and reserves. Energy balancing within-day should continue to be mainly delivered by supply and demand responding to price signals in liquid markets. As markets for zero carbon sources of Within-Day Flexibility develop and mature, there may be times when the ESO needs to intervene, to ensure price signals can incentivise efficient response from parties that can provide flexibility. We expect energy balancing over longer time periods will continue to be delivered by a mix of wholesale electricity markets and interventions, with future interventions addressing both undersupply and oversupply. Efficient zero carbon balancing of long periods of over and under supply will require a mix of long duration storage, baseload generation, dispatchable generation, dispatchable demand and curtailment.

The responsibility for resilience of energy balancing is shared between the ESO and the Department of Business, Energy and Industrial Strategy (BEIS). We are responsible for managing the frequency; we decide the mix and volume of products and services to buy, and we instruct them to deliver. For Within-Day Flexibility and Adequacy we act mainly as an advisor to BEIS who determine the market arrangements that deliver these services. For example, BEIS decide the capacity to be purchased in each Capacity Market auction (see the Capacity Market Auction Parameters for July 2022), they will set the security standards for Energy Smart Appliances (see the Smart and Secure Electricity System consultation), and they are reviewing electricity market arrangements (see Review of Electricity Market Arrangements (REMA) consultation).

Operability Strategy Report / Balancing the System / 62


Frequency

# Frequency

## Summary

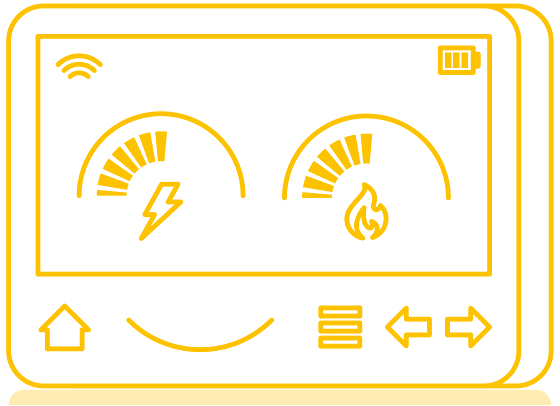
Frequency control is achieved through two types of service: response and reserve. Frequency response services are automatically activated using a measurement of frequency to determine an appropriate change in active power. Reserve is dispatched manually by a control room operator following an observed event or in anticipation of a system need. Both response and reserve can deliver a change in active power, provided by a source of either generation or demand.

The fundamental aim of our frequency control strategy is to maintain system frequency at the target of 50Hz. While maintaining the frequency, we must also balance the costs and impacts of our actions against the residual level of risk and benefits delivered to the end consumer.

In this chapter we look at the frequency control obligations and how these translate into requirements for response and reserve services. We also look at factors that might influence or change our requirements between now and 2035.

## What do we mean by Frequency?

**Frequency is a measure of the balance between supply and demand. We use response and reserve services to correct imbalances and maintain system frequency close to the target of 50Hz.**



Operability Strategy Report / Balancing the System / 64

# Frequency

## What are our obligations and what are the future operability challenges?

### Obligations

The Security and Quality of Supply Standards (SQSS) describes the requirements for controlling frequency, both pre-fault (steady-state) and post-fault (transient). It requires that we operate the network and avoid 'unacceptable frequency conditions' in a number of scenarios. These unacceptable conditions are split into two categories and are defined below:

1. Steady-state frequency moving outside of 49.5Hz or 50.5Hz

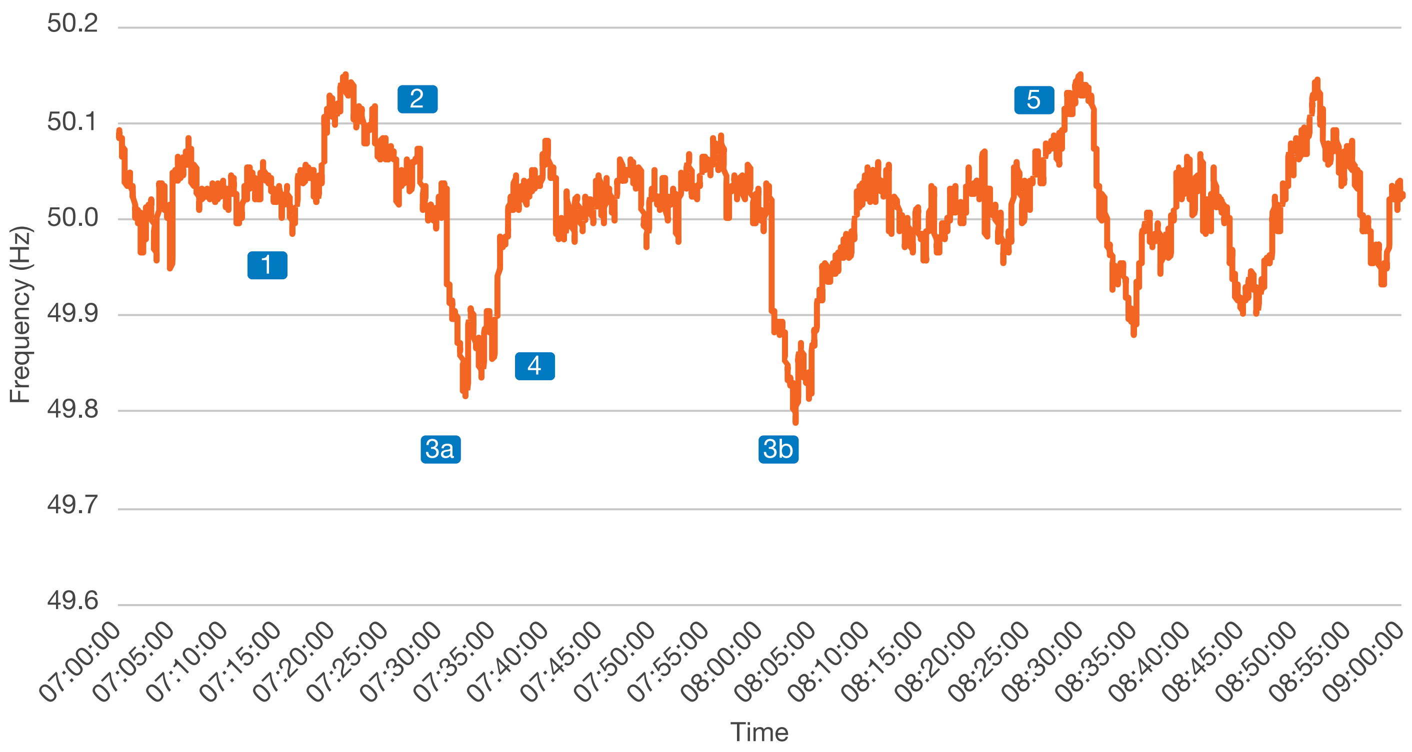
2. Transient frequency deviations outside of 49.5Hz or 50.5Hz – unless infrequent and tolerable

### Steady-State Frequency

The first of these obligations relates to regulating frequency during normal operating conditions. System frequency can be moved away from 50Hz not only by unexpected faults, but by gradual supply and demand imbalances and independent generator actions. For these reasons services are required to manage steady-state frequency.

This frequency trace can be broken down into 5 key stages to show the need for steady-state frequency management. In the example there have been no faults, but we had to rely on automatic response and manual reserve services to ensure frequency is regulated between 49.5Hz and 50.5Hz.

### System Frequency




Operability Strategy Report / Balancing the System / 65

# Frequency

## Transient Deviations

Transient frequency management mitigates the impact of faults on system frequency, this can be described as post-fault containment.

The frequency obligations around post-fault containment have remained largely unchanged since the introduction of the Frequency Risk and Control Report (FRCR) in 2021. The FRCR is reviewed annually and defines which events and deviations are classed as infrequent and tolerable. The FRCR states that frequency is allowed to deviate between -0.8Hz and +0.5Hz depending on several factors:

- The event which causes the deviation
- The size of the deviation
- The duration of the deviation
- The likelihood of the deviation occurring

Therefore, the FRCR informs both the ESO and wider stakeholders about the two key factors relating to transient frequency deviations:

- The events that must be secured
- The standard to which the events must be secured (i.e what is tolerable)

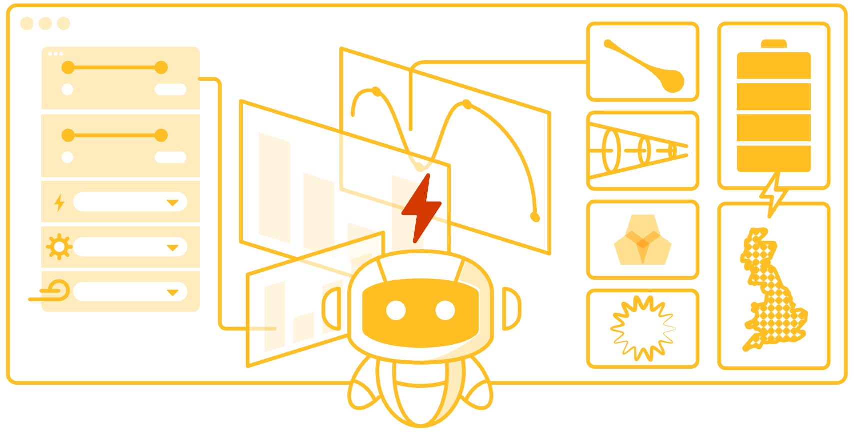
Later in this chapter we look at how these obligations translate into requirements for response and reserve services.

## Recovery and Restoration

The System Operator Guidelines (SOGL) describes the obligations on all system operators in Europe, and these obligations are now part of UK law. For GB the obligations are:

- That frequency must be recovered to +/- 0.5Hz within 60 seconds
- And restored to +/- 0.2Hz within 15 minutes

These obligations have helped to shape key design elements of the new reserve services we are launching over the next few years. For example, the quick and slow reserve services will help us meet the recovery (60 seconds) and restoration (15 minutes) obligations respectively.




Operability Strategy Report / Balancing the System / 66

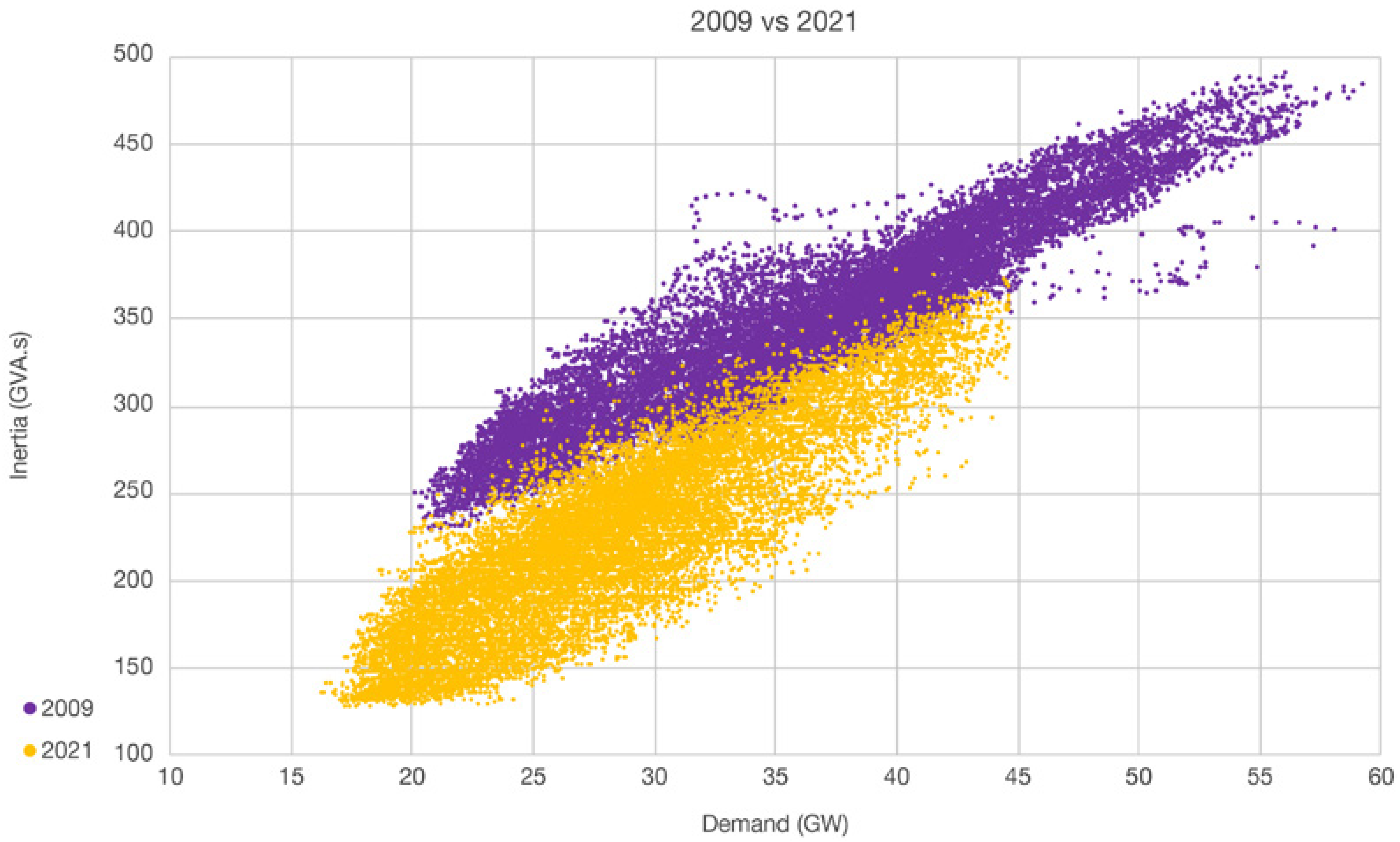
## Future Operability Challenges

### Falling Inertia

In the last decade the average annual system inertia has fallen by around 40%. Lower inertia means that system frequency is less resistant to change, so it will change more quickly when subject to an event, like a sudden loss of generation or demand.

Today our policy is to operate with a minimum inertia of 140GVA.s. The four Future Energy Scenarios (FES) indicate a decline in system inertia by 2050. The graph compares the system inertia between 2009 and 2021, demonstrating the significant decline in inertia that has already been seen on the network. This decline in inertia indicates that operating to the 140GVA.s minimum inertia policy may become more challenging. The minimum inertia policy is the focus of the 2023 FRCR report to see if a different approach would provide better value vs risk.

### Inertia vs Demand




Operability Strategy Report / Balancing the System / 67

# Frequency



## Increasing Loss Sizes

New connections, both interconnectors and generators, are increasing in capacity and are therefore increasing the size of the largest loss. The larger the loss the more actions need to be taken to protect the network before an event and to recover post an event. Currently the North Sea Link, at 1400MW, is the largest generation or demand loss on the network. This will change with time as new equipment is connected to the network.

| 2021 | 2023 | 2025 | 2029 |
|---|---|---|---|
| **North Sea Link** @ 1400MW | **Viking Link** @ 1400MW | **Damhead Creek 2** @ 1800MW | **EuroLink** @ 1800MW |

Operability Strategy Report / Balancing the System / 68

# Frequency

## Operating Conditions

The combination of lower inertia and larger losses means that the frequency can move quickly. In turn this means that frequency containment services need to be fast enough to arrest the change in frequency. This is one of the reasons that led us to develop a suite of new response and reserve services.

- Dynamic Containment, Dynamic Regulation and Dynamic Moderation are all new response services that are now live on the system.
- Quick reserve is a new service which will be used to recover frequency back towards 50Hz mainly during normal conditions.
- Our current restoration service, Short-Term Operating Reserve (STOR), will be replaced by Slow Reserve which will recover frequency to 0.2Hz within 15 minutes. Both Quick and Slow Reserve services are the next to be launched within our response and reserve reform programme.

## The Accelerated Loss of Mains Change Programme (ALoMCP)

The ALoMCP was implemented to bring forward the dates by which distributed generators would upgrade their protection relays. This upgrade would make them less sensitive to network disturbances. Overall this improves system resilience and supports wider initiatives, helping to meet the UK's net zero targets.

- The programme has significantly reduced the size of potential Rate of Change of Frequency (RoCoF) and Vector Shift losses, making frequency easier to manage should an event occur.
- The programme finished on the 31 August 2022 with work continuing until the end of 2022 to ensure generator compliance and to help enforce compliance beyond the programme's completion date.
- More information will be published to the relevant stakeholders when required.



Operability Strategy Report / Balancing the System / 69

# Frequency

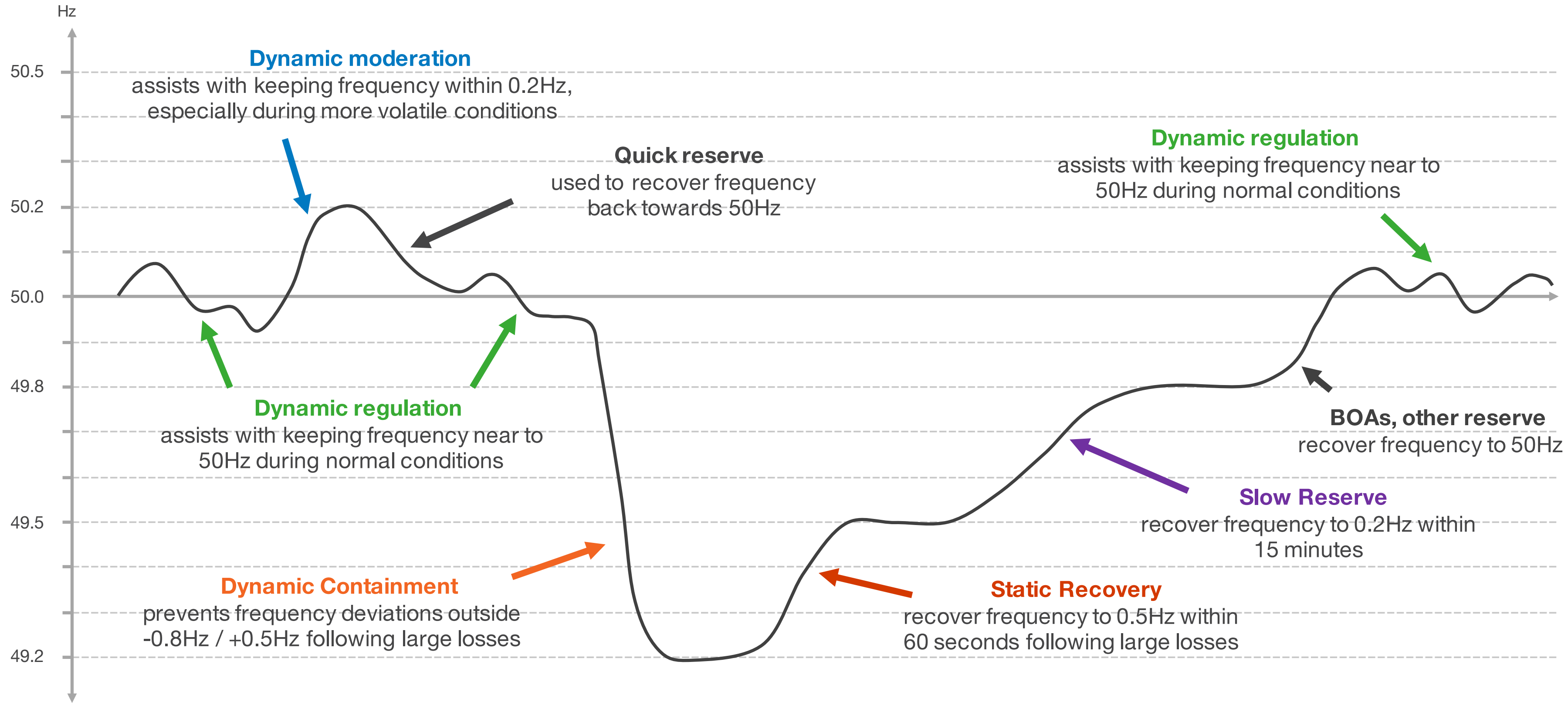
## What capability do we need to meet these changing operability challenges?

Combining the obligations on frequency control from SQSS, FRCR and SOGL we can put together a picture of the frequency regulation and restoration process.

1. We aim to keep the frequency near to 50Hz, to be ready for whenever a large generation or demand loss occurs
2. We must regulate steady-state frequency within the statutory limits of +/-0.5Hz
3. We must contain the frequency for events and to the standards set out in the FRCR
4. We must recover frequency to the statutory range (+/-0.5Hz) within 60 seconds
5. We must restore frequency to the operational range (+/-0.2Hz) within 15 minutes
6. We can then use other reserves and Bid-Offer-Acceptances (BOAs) within the Balancing Mechanism (BM) to bring the frequency back to our target of 50Hz

With these obligations in mind, we are designing services and sizing requirements that will meet our needs both today and out to 2025.

### Frequency Control Process




Operability Strategy Report / Balancing the System / 70

# Frequency

## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

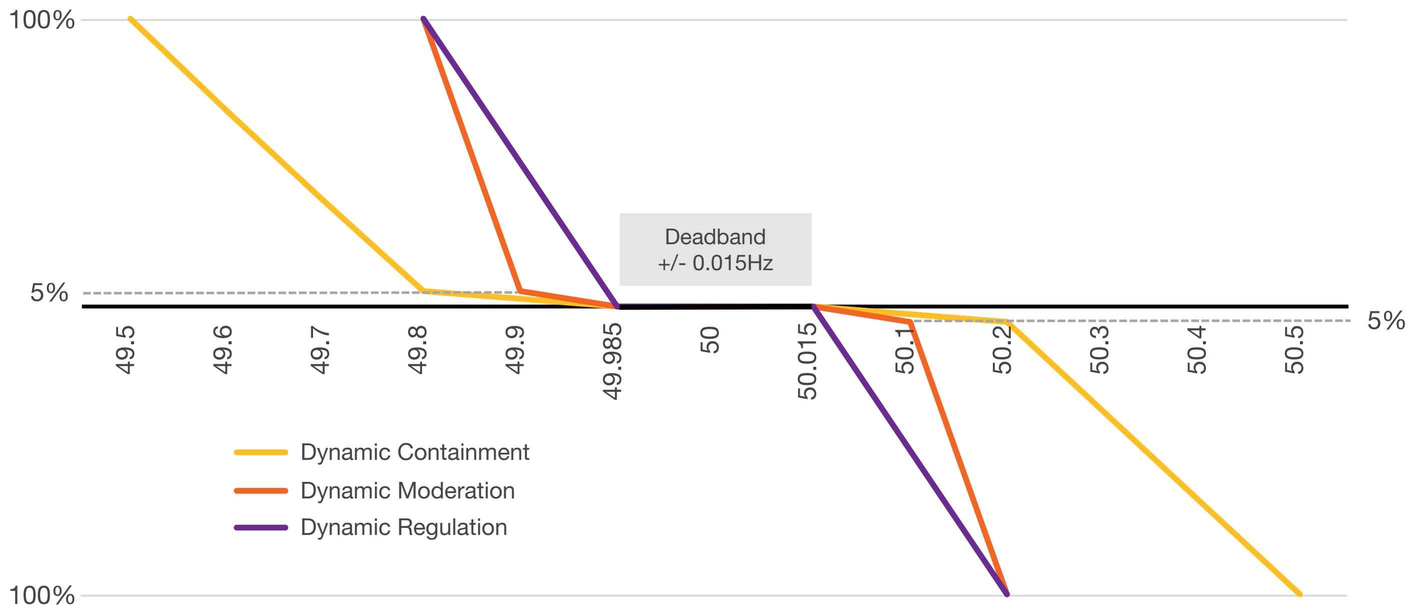
### Regulate

- Frequency regulation in steady-state pre-fault conditions will be met by a combination of Dynamic Regulation and Dynamic Moderation. Both of these services launched in 2022.
- We currently procure up to 300MW each of Dynamic Regulation and Dynamic Moderation.
- Our requirement for regulation services is highest when the system balance is subject to unforeseen imbalances between supply and demand.
- These two response services stop deviations going outside of operational limits (+/- 0.2Hz). We then use a combination of fast-acting reserves and Bid-Offer-Acceptances (BOAs) within the Balancing Mechanism (BM) to return the frequency to 50Hz.
- We are planning to launch Quick Reserve in 2023 as our new fast-acting reserve service and expect to buy up to 1400MW by 2025.
- We also use BOAs to return the frequency to 50Hz, and to prevent deviations towards the edge of operational limits when we foresee upcoming imbalance. A new service, provisionally called ‘Balancing Reserve’, is being explored to ensure we are using the most effective means of procuring the capacity in the BM to balance the system. Communication on this will be delivered to the market through the Ancillary Service Reforms.

### Contain

- Our principle containment service is Dynamic Containment, the low-frequency variant was launched in October 2020 and the high-frequency variant followed in November 2021.
- Our requirement for containment is driven by the size of the largest loss on the system and impacted by the level of inertia. The FRCR determines which losses to secure as well as a minimum level of inertia, and therefore any recommendations from the FRCR can have significant impact on our requirement for containment services.
- By 2025 we may be buying up to 1400MW of Dynamic Containment to secure several large infeed losses. If a larger loss connects, such as Damhead Creek 2, we may need to buy more. We expect to see periods of exports over the interconnectors which means that our high frequency response requirement and negative reserve requirement will be larger on a more frequent basis.

### Service Comparison



# Frequency



## Transient Recovery

- We have identified a gap within our services due to the ending of monthly procurements of dynamic Firm Frequency Response (FFR) and secondary static response.
- A service is required to recover frequency to +/- 0.5Hz within 60 seconds following large scale losses.
- We have been working through options to meet this need and a new service has been identified called Static Recovery. Communication on this will be delivered to the market through Ancillary Service Reforms.

## Steady-State Restoration

- Our principle restoration service is Short-Term Operating Reserve (STOR) which will transition into the new Slow Reserve service.
- Frequency restoration services will be sized similarly to recovery services, by 2025 we could buy up to 1400MW of Slow Reserve. If it offers good value, additional volume may be bought to assist with pre-fault frequency regulation and proactive imbalance management.

## Replace

- The final stage, reserve replacement, is completed via flexibility accessed in the BM and self-correction by market participants. This includes BOAs, and the capacity we are looking to buy through Balancing Reserve.

Operability Strategy Report / Balancing the System / 72

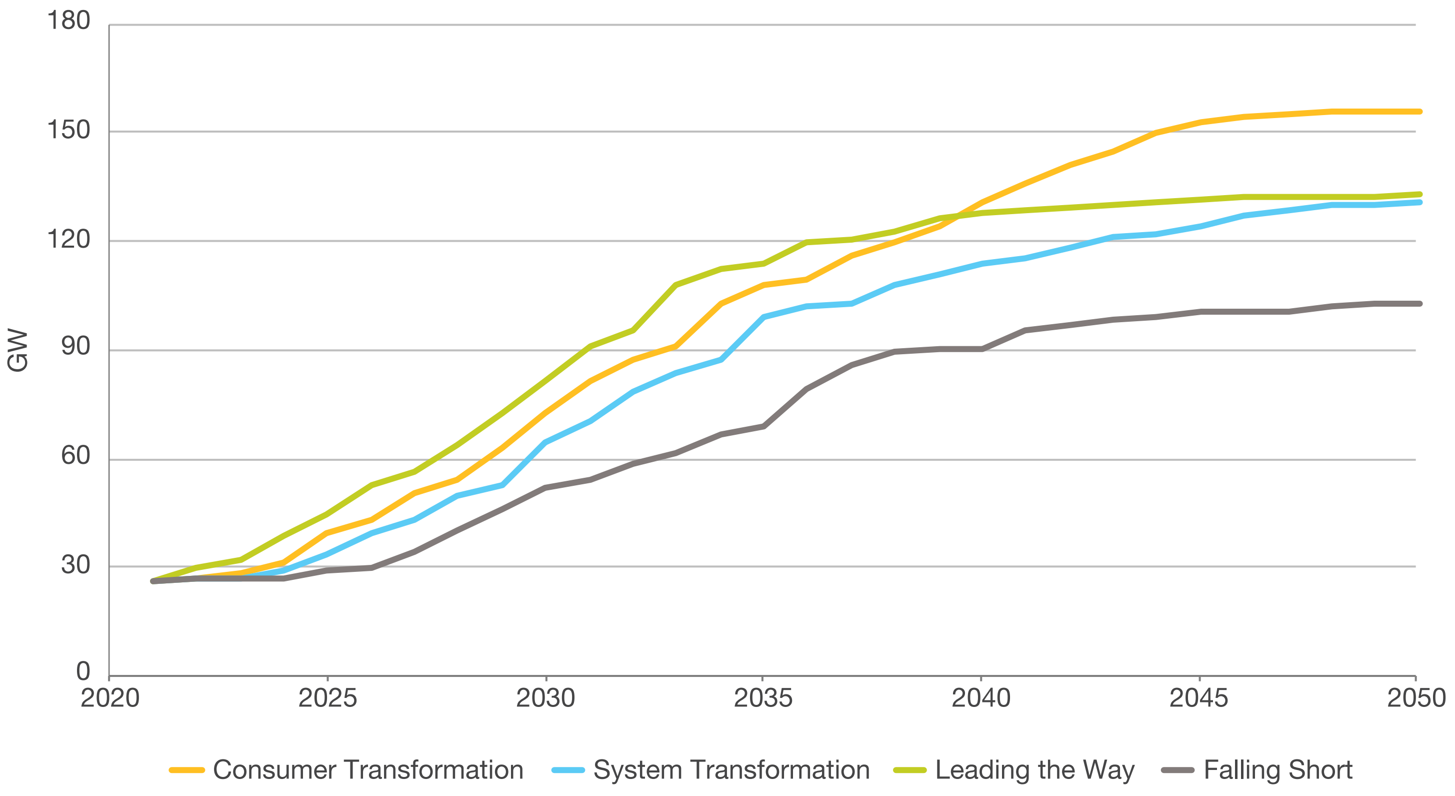
# Frequency

## How do requirements change under differing Future Energy Scenarios?

Each future energy scenario assumes a different level of inertia on the network, with all four scenarios projecting less inertia than is currently on the system. Inertia levels largely impact the volume of response that is required on the network, with lower inertia systems requiring more and faster frequency response.

More asynchronous generation and variable sources of generation create uncertainty in generation and demand forecasts and increased fluctuations in frequency within steady-state limits. Scenarios with more asynchronous and variable sources of generation will likely require more reserve and response.

Generation Capacity – Total wind generation capacity (onshore and offshore)




Wind Generation Capacity | Solar Generation Capacity

Operability Strategy Report / Balancing the System / 73

## What is the next big operational challenge?

### Currently the main challenges on the network are driven by asset size and inertia levels on the network. In future, we expect a greater impact from four key areas:

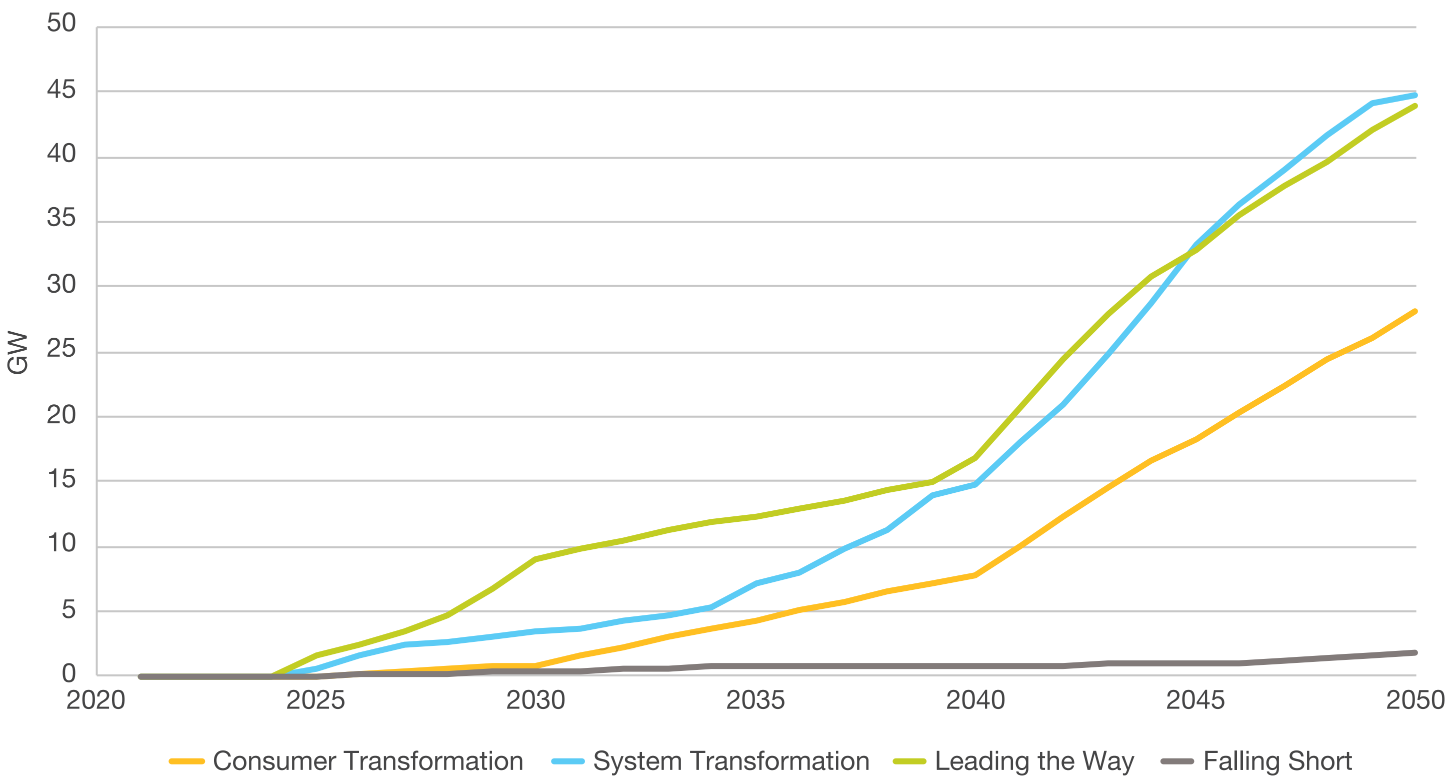
### Weather

- More variable sources of generation connecting to the network

### Consumer behaviour (domestic, commercial and industrial)

- Increasing volumes of demand flexibility, such as increasing numbers of Electric Vehicles (EVs) charging, increasing volumes of smart appliances in homes and the introduction of larger scale electrolysis

Total electrolysis capacity: all network-connected electrolysers (including nuclear)




Total electrolysis capacity

Household appliance ownership

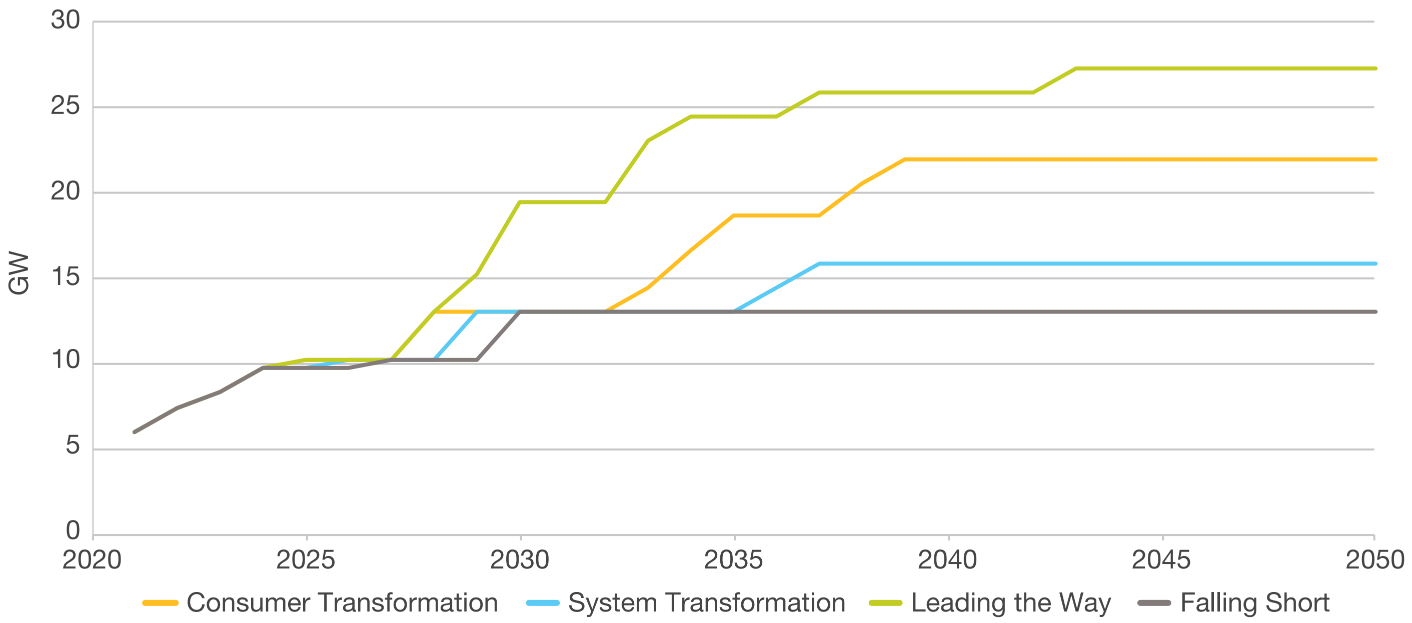
Operability Strategy Report / Balancing the System / 74

# Frequency

## Price

- Any changes in the price of electricity may impact consumer behaviour, as well as any specific price incentives like the demand flexibility arrangements for winter 2022/23.
- Market arrangements mean that changes in price over the course of the day, or over certain periods, can lead to coordinated behaviour which can affect frequency.
  Three examples of this are:
  - Periods of rapid ramping due to an increase in the number of continental interconnectors
  - Periods of rapid ramping due to coordinated charging of EVs
  - Large volumes of Contract for Difference generation simultaneously ramping down

### Installed interconnector capacity (GW)




## Location

- Greater locational fluctuations in frequency may occur due to lower inertia and increased largest loss size.
- Our studies show that our new response services and locational distribution of providers is currently sufficient for managing the impact of locational frequency. We will continue to monitor potential future requirements and solutions as part of our frequency strategy, and to determine if regional frequency products are required in future.

The interaction between these different areas is likely to create more complexity in assessing both our frequency risks and our need for controls to manage frequency in real-time.

# Within-Day Flexibility

ESO

# Within-Day Flexibility

## What do we mean by Within-Day Flexibility?

**Within-Day Flexibility means being able to adjust the flexible parts of supply and demand as the inflexible parts vary over the day.**

### Supply

The main source of inflexible, variable supply is variable sources of generation, which is growing as we decarbonise. Solar power varies during the day driven by the time of year and height of the sun, but also due to cloud cover changes. Wind generation varies with wind speeds, driven by the weather, in patterns that can change from minute to minute, and can also persist for many days.

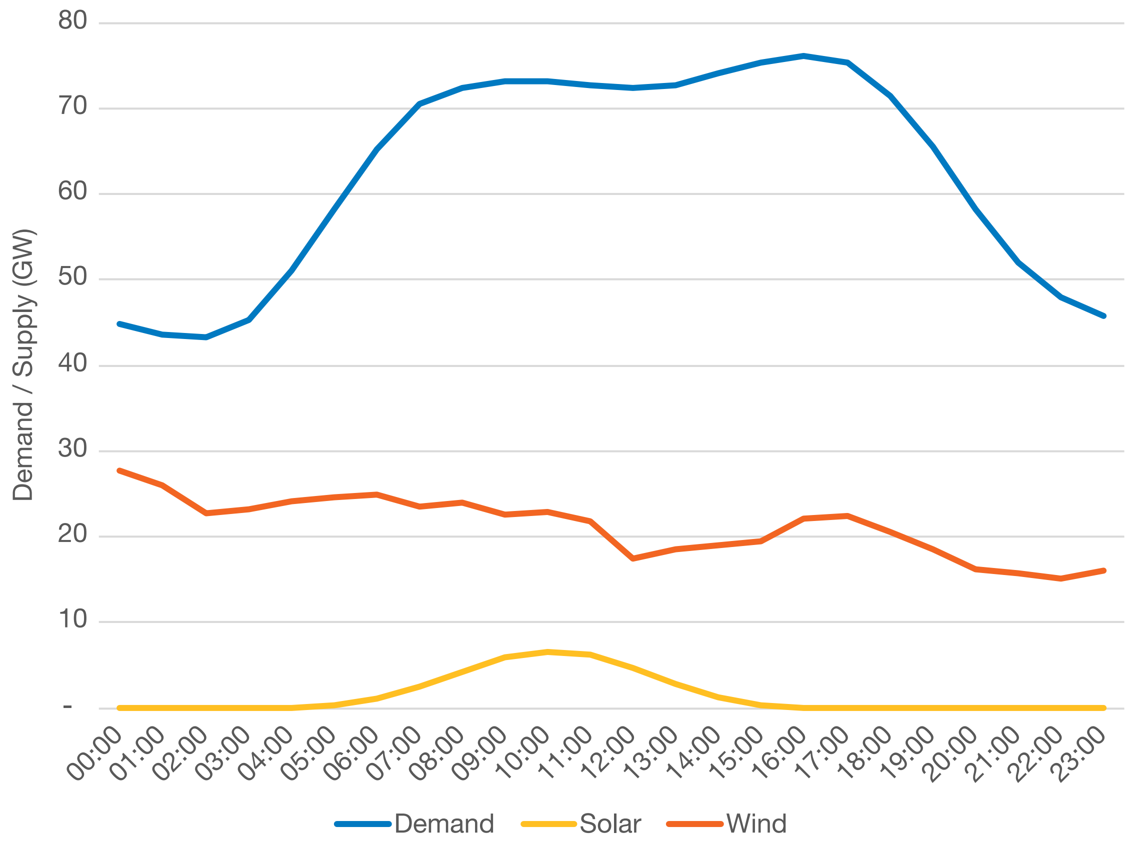
### Demand

Demand varies through the day based on human behaviour. Some demand is needed at specific times and is non-negotiable: people cook food before they need to eat and use lighting when it gets dark. Electrification of heat and transport will cause a rapid increase in electrical demand and the parts of this that do not behave flexibly will add to the variability that needs balancing.

Dispatchable generation is very well suited to balancing these within-day variations in supply and demand and currently provides the vast majority of it. To achieve a zero carbon electricity system we will have to replace this fossil fuelled flexibility with new, zero carbon solutions that move supply and demand through time. Examples of this include:

- Domestic consumers shifting when they charge their Electric Vehicles or operate their heat pumps, to reduce their contribution to peak demand
- Industrial and commercial customers optimising their operation to reduce their electricity consumption at times of the day with highest prices
- Storage operators using solar power to charge during the day and then discharging when it gets dark

**Within-day variation in demand, solar generation, and wind generation, on a day in January in 2035 (Consumer Transformation scenario)**





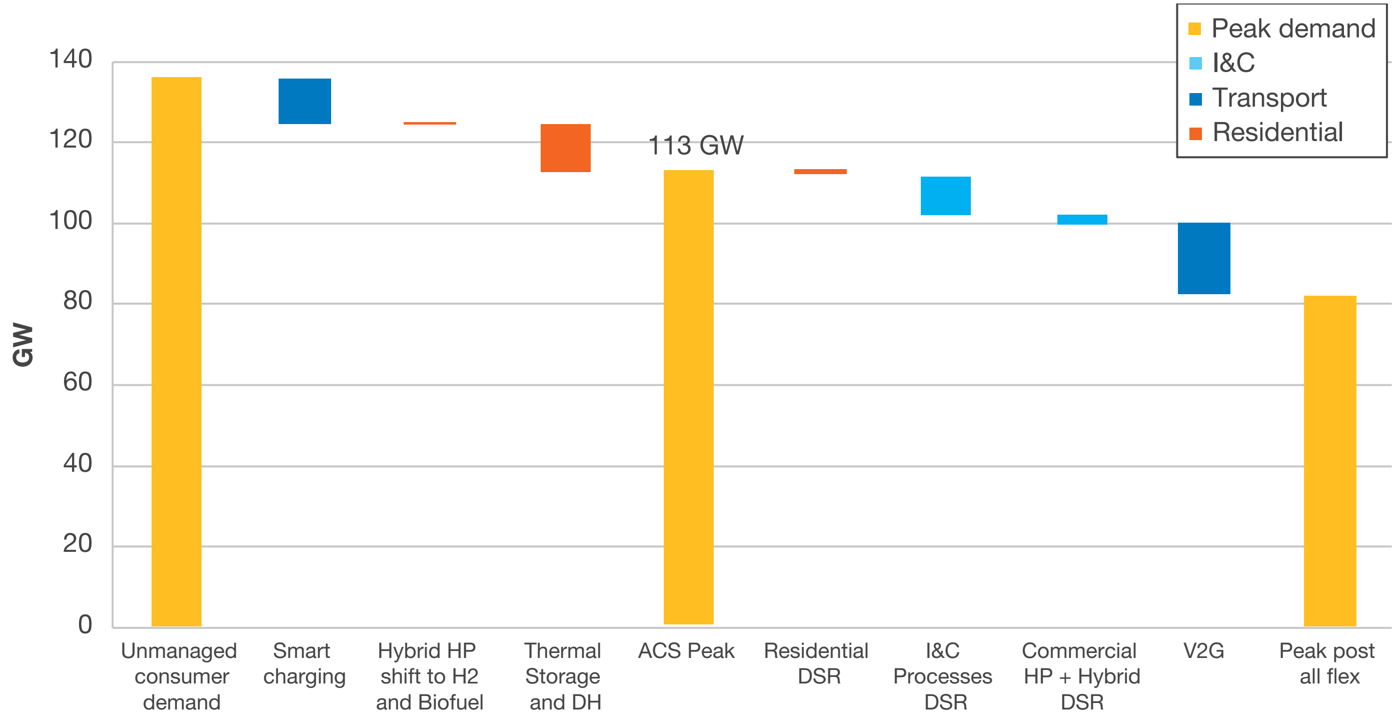

Operability Strategy Report / Balancing the System / 77

## What are the future operability challenges?

### Peak Demands

The first operability challenge we expect Within-Day Flexibility to support is reducing the size of demand peaks, particularly over the winter when demand is higher. The demand peaks last for a few hours and occur day after day, which is an ideal pattern for Within-Day Flexibility. This peak demand period is when energy prices tend to be highest, so flexibility provided here has a particularly large impact on consumers' bills. Reducing peak demand can also help with other operability challenges; lower daily peaks can make longer duration adequacy challenges easier to manage and reduce the urgency of transmission and distribution network reinforcements.

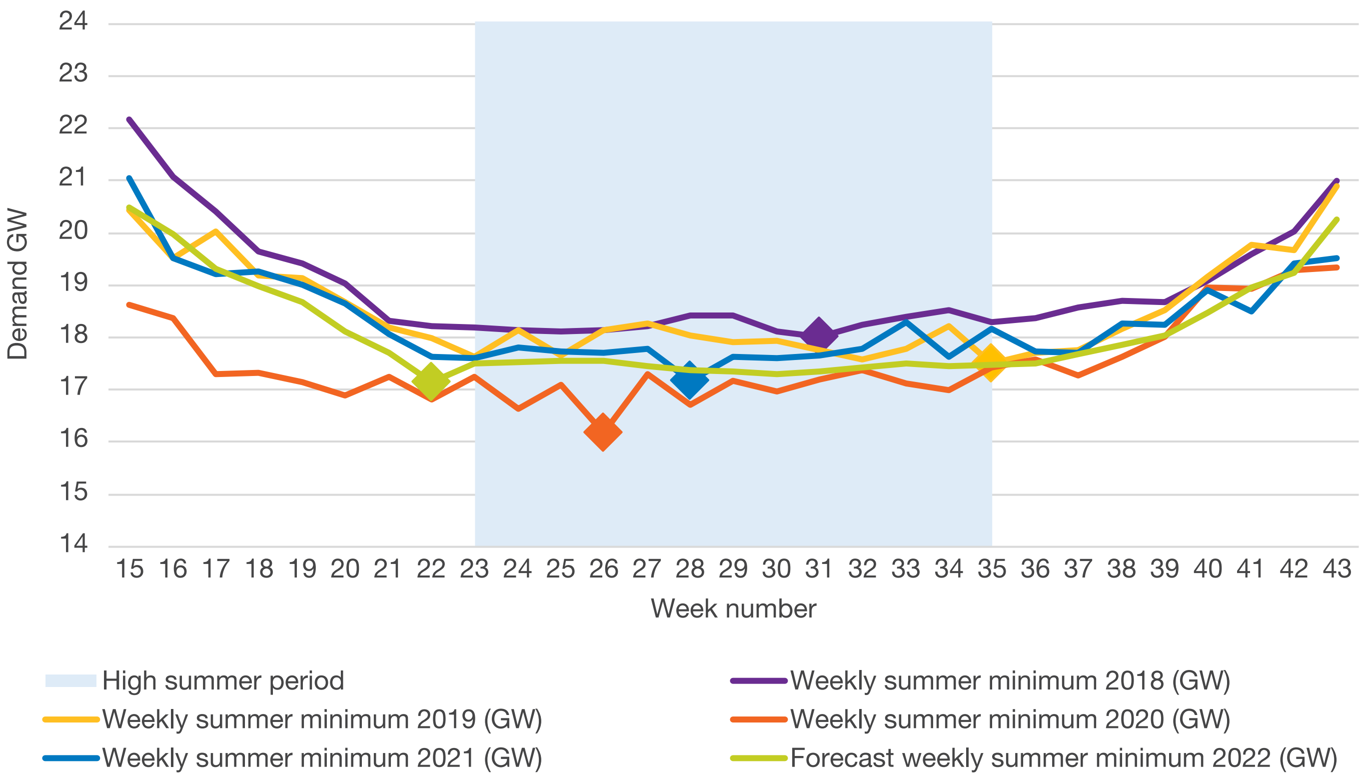
Impact of flexible DSR technologies on peak demands in 2050 Consumer Transformation




Consumer Transformation | System Transformation | Leading the Way | Falling Short

# Within-Day Flexibility

### Historic minimum transmission system demand (and forecast for summer 2022 as at April 2022)




### Minimum Demands

The next operability challenge Within-Day Flexibility can help with is likely to be increasing minimum demands. As deployment of solar PV and energy efficiency measures continue to grow, the minimum demands seen on the transmission system, just after noon on summer days, will continue to fall. When transmission system demand is very low it can cause multiple operability challenges including with reactive power, inertia, and short circuit levels. During the summer of 2020, when Covid lockdown took summer minimum demand to previously unseen lows, the ESO had to take actions to ensure the security of the system through curtailment of renewables.

In future, Within-Day Flexibility, such as through an incentive to charge Electric Vehicles in the early afternoon, could provide a more efficient way to ensure system security by increasing demand when supply is high.

Further into the future, operability challenges that Within-Day Flexibility could help with could include:

- Following renewable generation through the day to reduce curtailment
- Reducing forecast errors in supply and demand
- Reducing the steepness of supply or demand ramp rates caused by other parts of the system

Operability Strategy Report / Balancing the System / 79

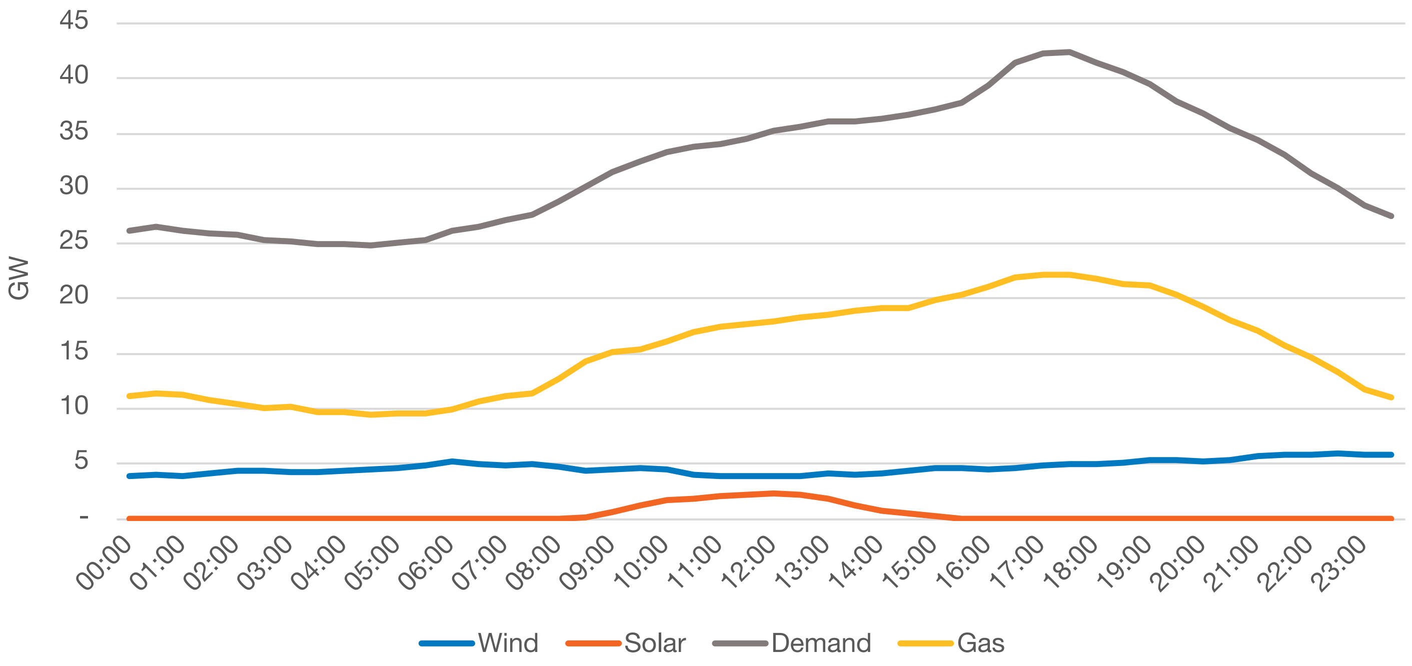
# Within-Day Flexibility

## What capability do we need to meet these changing operability challenges?

### The market will deliver

The key capability needed to unlock Within-Day Flexibility is changes to market arrangements so that parties able to provide flexibility are exposed to price signals that reveal its value.

Gas, wind and solar generation and demand over a day (02/01/21)




02/01/21 22/01/21

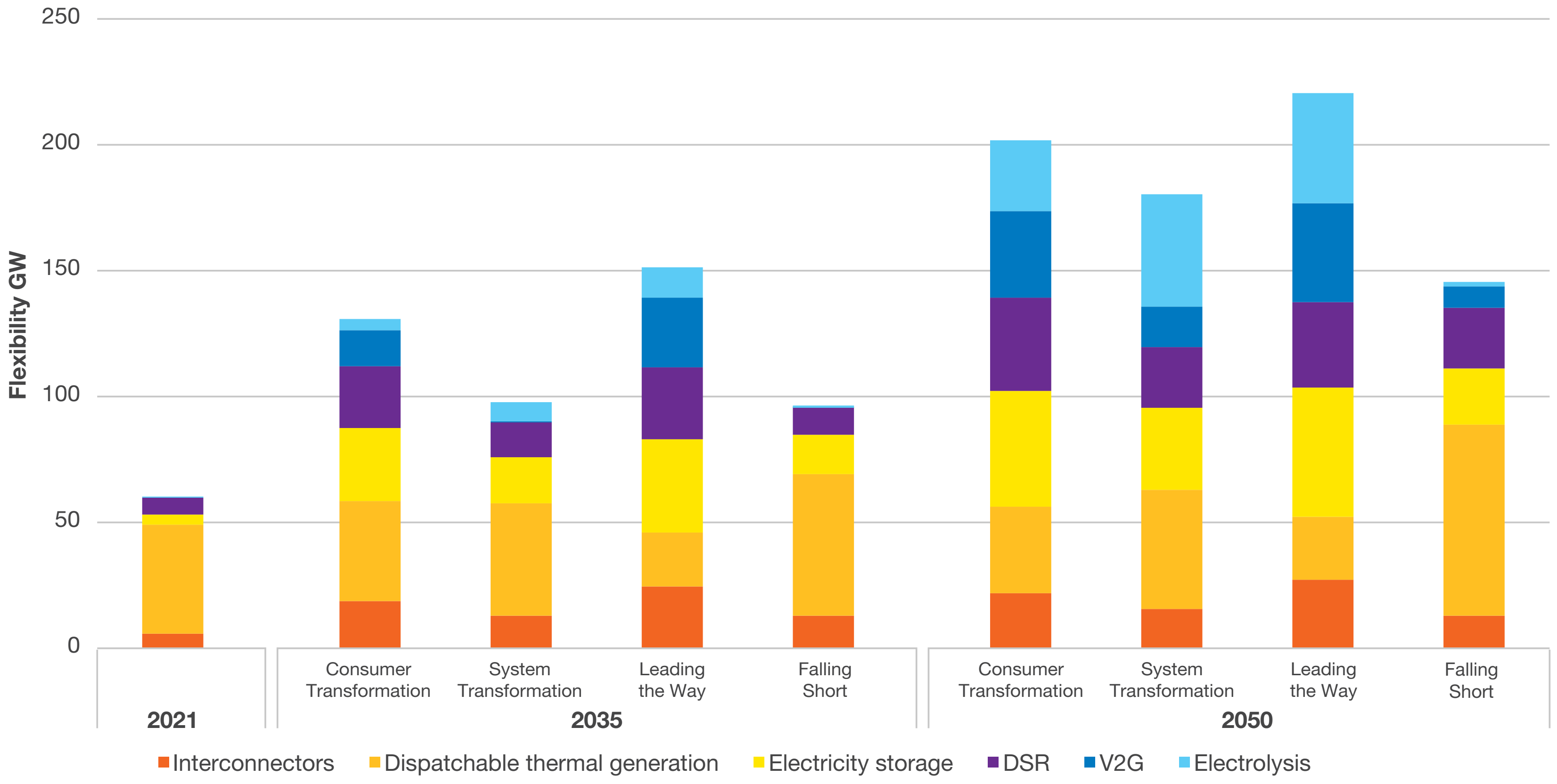
Currently, Within-Day Flexibility is mostly delivered by the wholesale market. The price for power changes every half hour, and this variation in price drives supply, and to a lesser extent demand, to increase and decrease until they balance. The flexibility in supply mainly comes from dispatchable generation and the flexibility in demand mainly comes from industrial and commercial customers. Interconnection with electricity systems in other countries provides flexibility in supply and demand. There is little contribution to Within-Day Flexibility from domestic consumers, mainly because they are not exposed to the varying wholesale price. Instead, domestic consumers tend to face a flat electricity price and are not metered or settled on a time of use basis, so they have no incentive for more flexible demand behaviour.

In the long term, we expect Within-Day Flexibility to be delivered in a similar way, with prices driving both wholesale market activity and energy consumption, causing supply and demand to adjust until they balance. Market-wide half hourly settlement (MHHS) is planned to be introduced in 2025 and within a few years most domestic demand will have the opportunity to be exposed to varying price signals, such as dynamic Time of Use Tariffs. The BEIS REMA process is considering how electricity markets may be reformed, including by creating more temporally and locationally granular price signals. These changes, in combination with BEIS work on Energy Retail Market Reform and delivering a Smart and Secure Electricity System, will unlock new sources of flexibility.

Operability Strategy Report / Balancing the System / 80

# Within-Day Flexibility

## Sources of flexibility changing between 2021, 2035 and 2050




During the 2030s the balance will shift to Within-Day Flexibility mostly being provided by new technologies. These include storage and new flexible demand technologies, which make it easier to shift when electricity is consumed, such as smart charging Electric Vehicles (EVs), vehicle to grid, smart heating, thermal storage, and smart appliances.

## Bridging the gap

The timelines for the market arrangements, consumer incentives, technology roll-outs and data provisioning are not currently clear. The system need for this capability might arise before the market is fully able to provide it. If necessary, the ESO will bridge gaps between stages by creating temporary alternative mechanisms to help price signals get through to new providers of flexibility.

We will also continue to run trials so that we, and future participants in flexibility markets, can continually learn, informing more appropriate enduring arrangements. The recently developed Demand Flexibility Service is an example of this. It creates a price signal for demand side flexibility, allowing the ESO to use capacity that would otherwise be inaccessible, lowering the cost of managing generation margins for system security over the winter.

Operability Strategy Report / Balancing the System / 81

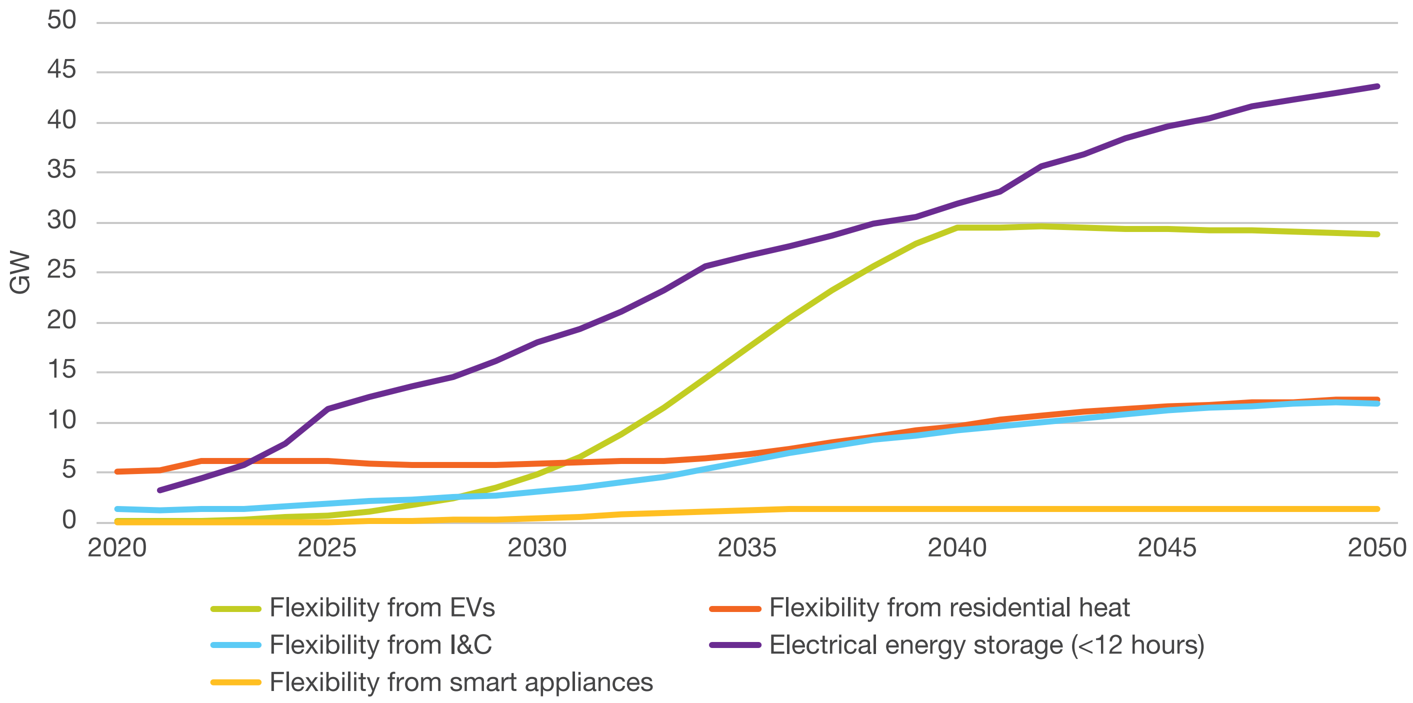
# Within-Day Flexibility

## Sources of Within-Day Flexibility

The sources of Within-Day Flexibility will evolve over time. Electricity storage with a duration of less than 12 hours will be the largest source of Within-Day Flexibility, although it may use some of its capacity to provide other services. Electricity storage with a duration longer than 12 hours could not fully charge and discharge within a day, so is excluded from the graph. There is already around 5GW of this storage connected to the system, providing services and flexibility, and we expect the capacity to continue growing, with over 1GW on average added each year until 2050. Over time we expect the stack of services provided by electricity storage to include an increasing share of energy arbitrage as the value of Within-Day Flexibility increases.

Electric vehicles (EVs) will provide by far the fastest growing source of Within-Day Flexibility. Residential flexibility provided to the system currently amounts to a few hundred MW, most of this coming from smart charging of EVs. This flexibility from EVs is expected to grow very rapidly, to 1-8GW in 2030 and 5-27GW in 2035. Initially this flexibility will all come from smart charging; in the early 2030s significant additional volumes of flexibility will be delivered by power flowing from charged vehicles back to the system (Vehicle to Grid, V2G).

## Sources of Within-Day Flexibility growing over time (Consumer Transformation scenario)




Operability Strategy Report / Balancing the System / 82

# Within-Day Flexibility



Domestic heat, industrial & commercial (I&C) demand and smart appliances will be important but smaller sources of flexibility. I&C customers already adjust the timing of their processes to avoid high prices and we expect this to increase steadily towards 2050. Some residential heating already uses storage, in the form of storage heaters or hot water tanks, to move the electrical demand for creating heat away from peak demand times. From the 2030s we expect heating demand to become more flexible, responding to dynamic price signals, and providing about twice as much flexibility by 2050. Flexible demand from other smart appliances will provide about 1GW in the 2030s.

Flexibility from grid-scale storage and I&C customers tends to be half-hourly settled and already selling products and services through existing frameworks and markets. Flexibility from appliances connected to domestic meters, such as EVs, heating, appliances and small batteries, tends not to be half-hourly settled and faces more barriers to participating in markets for flexibility.

Operability Strategy Report / Balancing the System / 83

# Within-Day Flexibility

## What are the requirements for zero carbon operation in 2030?

The operational requirement for Within-Day Flexibility in 2030 will be to balance variability in supply and demand over a day, without using fossil fuelled generation. It will be necessary to efficiently coordinate this requirement with similar requirements for energy balancing at shorter and longer timescales, for Frequency and Adequacy. The Future Energy Scenarios indicate we will have 25-45GW of zero carbon Within-Day Flexibility by 2030.

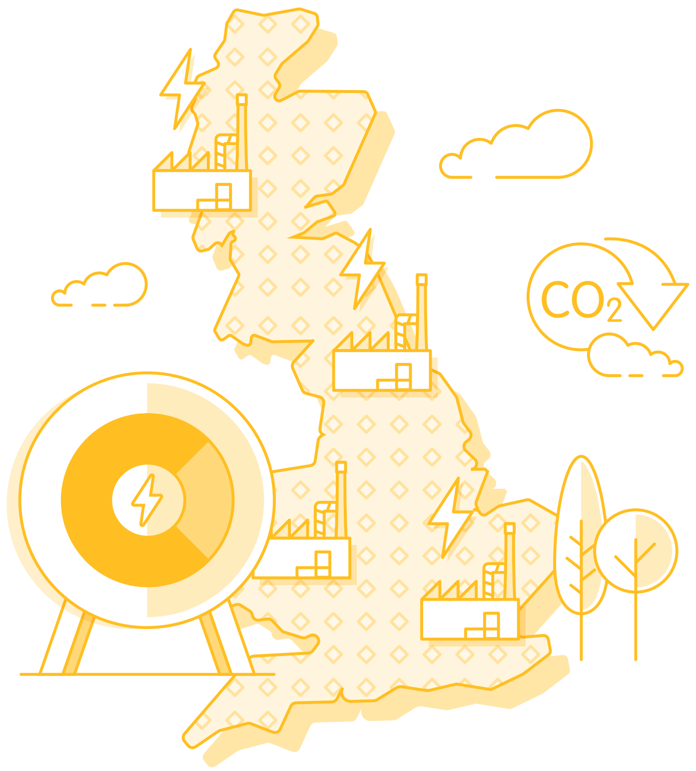
The ability to accurately and reliably influence supply and demand over the course of a day will change power flows on the network, which could reduce the challenges and costs all of the operability dimensions. For example:

- Increasing demand for a few hours over the summer minimum could reduce reactive power and stability challenges
- Reducing flows over a congested part of the network could reduce the other actions needed to manage thermal constraints
- Reducing the severity of rapid transitions of non-negotiable demand and renewable supply could reduce the amount of response and reserve that needs to be held to manage the frequency.

Our estimates of future levels of Within-Day Flexibility are likely to be quite uncertain for a while. The growth of some sources of flexibility will be extremely rapid and will be driven by things the ESO has little control over, such as consumer behaviour. Significant work will be required to improve our understanding of what drives the variability in how much Within-Day Flexibility will be provided in different situations, and therefore how much of it can be relied upon for planning assumptions. We expect the main long-term driver for Within-Day Flexibility to be price signals from power markets, which are currently under review with REMA. Until that concludes we will not know how much Within-Day Flexibility the new market arrangements will deliver and whether the ESO needs to take action to secure more.

Innovation projects, control room trials of novel approaches to buying demand side flexibility, and temporary arrangements such as our Demand Flexibility Service will give an indication of how much Within-Day Flexibility could be provided before the new market arrangements are established.

We want to work with the industry to understand this better. If you have insights you can share, please contact us at SOF@nationalgridESO.com





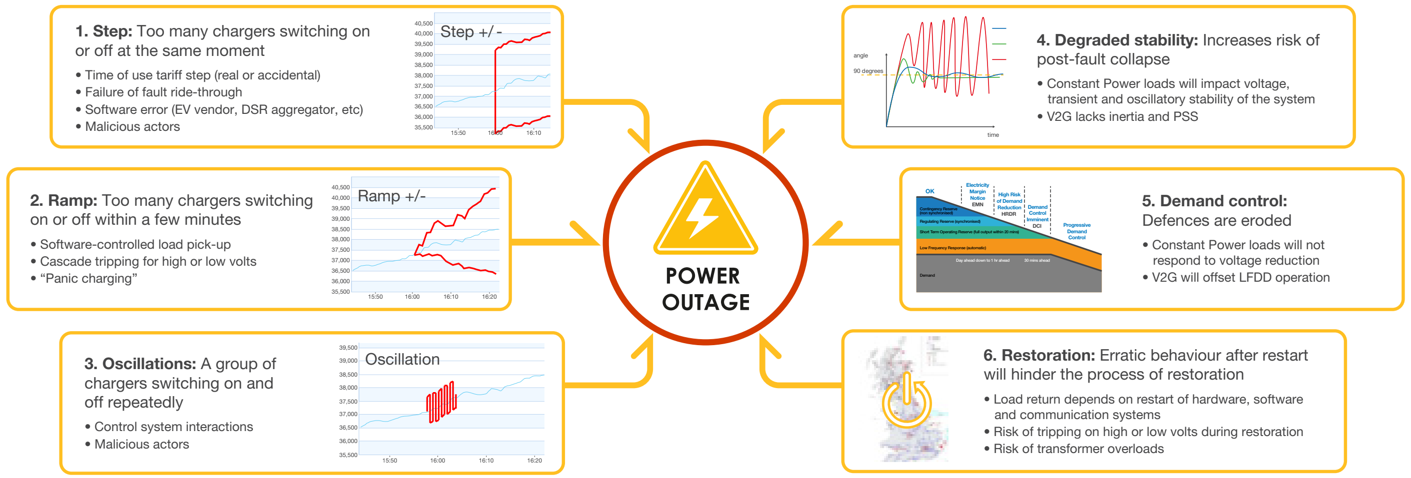
Operability Strategy Report / Balancing the System / 84

# Within-Day Flexibility

## What is the next big operational challenge?

The things that will provide Within-Day Flexibility could cause operability challenges once they reach sufficient scale. Our recent innovation project Resilient Electric Vehicle Charging identified six ways that EV charging could present risks to the security of the electricity system. Most of these risks could apply to other technologies providing Within-Day Flexibility.

### Six ways in which Electric Vehicle chargers could present a risk to electricity system security




Click to expand

It will be difficult to forecast how much flexibility will be provided at different times, for multiple reasons. We will have less experience of the technologies and associated behaviour behind the flexibility. The flexibility may be responding to price signals that we cannot see or forecast, and if the flexibility is distributed, we may have less visibility of what it is doing and has done, which will make it harder to extrapolate from this into the future.

These challenges to accurately forecasting Within-Day Flexibility will limit our ability to efficiently optimise costs while ensuring security:

- On investment timescales, e.g. network investment and Capacity Market auctions
- On planning timescales, e.g. scheduling outages
- On operational timescales, e.g. managing the cost of securing for faults

Many of the new sources of Within-Day Flexibility will be connected to distribution networks. Distribution Network Operators will need to use the same sources of flexibility to manage their own networks and will experience their own operability challenges caused by technologies. To achieve the best whole system outcomes, we will need to improve our coordination with DNOs through:

- Consistent and aligned approaches to procurement and dispatch
- Greater operational visibility
- Clear rules

Operability Strategy Report / Balancing the System / 85

# Adequacy

ESO

# Adequacy

## Summary

Adequacy measures whether there are sufficient available resources to meet electricity demand throughout the year. In Great Britain, this has traditionally meant having sufficient margins when demand is highest in winter.

We commissioned AFRY to undertake a long-term adequacy study to assess the risks to security of supply in a fully decarbonised power system and the resources needed to ensure adequacy in the 2030s. The study examines four different potential portfolios of resources – utilising different combinations of nuclear, CCS, hydrogen power generation and batteries. The purpose is not to identify a definitive pathway, or resource mix, for GB; but rather to explore the range and mix of options that could ensure adequacy, the implications of them and some of the trade-offs that might be required. This is a first step towards understanding the scale of the challenge facing GB.

The full report is available on our website and the key findings are:

- There is no trade-off between adequacy and meeting net zero but we need to bring forward investment in clean, reliable technologies.
- Understanding risks due to weather patterns will become increasingly important to ensure adequacy in a fully decarbonised system with high levels of weather-dependent generation.
- New modelling approaches and metrics will be required to assess risks to adequacy in a fully decarbonised power system.
- It will become more important to consider adequacy in the context of developing the right markets, the right networks and future operability challenges to be confident that adequacy is ensured in a cost-effective way.

There are also operability impacts to consider. Whilst there are many different pathways that can provide similar levels of adequacy, there are significant differences in their operability impact throughout the year. For example, a resource mix with high levels of renewables combined with significant levels of less flexible generation such as nuclear, will have a much higher level of surplus energy and renewable generation curtailment. While this poses little operational risk to security of supply, it does increase operational costs substantially. This is one of the next big future operability challenges.

## What do we mean by Adequacy?

**Adequacy measures whether there are sufficient available resources to meet electricity demand throughout the year. In Great Britain, this has traditionally meant having sufficient margins when demand is highest in winter.**



Operability Strategy Report / Balancing the System / 87

# Adequacy

## What are our obligations and what are the future operability challenges?

### The AFRY study found that understanding risks due to weather patterns will become increasingly important to ensure adequacy in a fully decarbonised system with high levels of weather-dependent generation.

Weather patterns will be the dominant driver of stress periods in a fully decarbonised power system. This represents a change for the GB system, as tight periods have traditionally been driven by plant availability and high demand.

New data sets will need to be developed to assess these risks appropriately.

The most challenging situations are likely to be weather patterns extending across North-West Europe that result in low wind during winter. Such weather patterns can lead to much longer periods of system tightness compared with those experienced today.

While batteries play an important role, the nature of these weather patterns means that adequacy cannot be ensured in a system that relies solely on batteries. This is shown in the AFRY study as we considered a case that relies on 6-hour batteries instead of any other new technologies. The case in the study showed a very high capacity (over 120GW) could not ensure adequacy, as the batteries could not provide sufficient energy to meet demand during prolonged adverse weather patterns (120GW of 6-hour batteries provides less than 1TWh of energy).

There will be greater inter-dependence with neighbouring countries who may be experiencing similar weather conditions at the same time as us. How reliant we wish to be on imports from other countries is likely to be a GB energy policy decision.

Operability Strategy Report / Balancing the System / 88

## What capability do we need to meet these changing operability challenges?

### The AFRY study found that there is no trade off between adequacy and meeting net zero but we need to bring forward investment in clean, reliable technologies.

Even at times of low output from weather-dependent renewable generation, it is possible to operate a fully decarbonised power system and meet customer demand. It will require large investment in clean, reliable technologies that are not weather-dependent. This could include: new nuclear, CCS, hydrogen power generation, new electricity storage or other technologies that can deliver energy on a scale of TWh or tens of TWh.

There is uncertainty in relying upon new technologies. They typically have long lead times and some need to be proven at commercial-scale. Any barriers to delivering this capacity at scale by 2035 should be identified and addressed to reduce dependence on unabated gas.

This study does not advocate for a preferred technology or combination of technologies in the future resource mix.

## What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

### The AFRY study found that new modelling approaches and metrics will be required to assess risks to adequacy in a fully decarbonised power system.

Great Britain currently has a statutory reliability standard of 3 hours loss of load expectation (LOLE).

The GB system is expected to evolve from one where tight periods are relatively short to one where they are much longer. Even though the duration of tight periods increases, the LOLE of the system remains broadly similar. This means that the inherent risk profile of the system is changing but the key metric is not.

The modelling suggests that the GB system will be more susceptible to events that have a lower likelihood of occurring but will have a greater impact if they materialise. This is evident from longer-duration weather events becoming increasingly dominant in driving stress periods, for a similar LOLE value. This means that in many years, no tight periods on the GB system would be expected, but occasionally in other years, there could be prolonged tight periods that are more challenging.

As the electricity system transitions to being fully decarbonised, industry and the government should work together to understand how to improve current approaches to the way that adequacy is measured. This could lead to new metrics that either support or replace existing ones such as LOLE.


Operability Strategy Report / Balancing the System / 89

## How do requirements change under differing Future Energy Scenarios?

The AFRY study is based on the Consumer Transformation (CT) scenario in the 2021 Future Energy Scenarios (FES). It was not possible to assess all scenarios in the FES due to the scope of the study. However, at a high level, the conclusions drawn will be valid across all FES scenarios that meet net zero.

## What is the next big operational challenge?

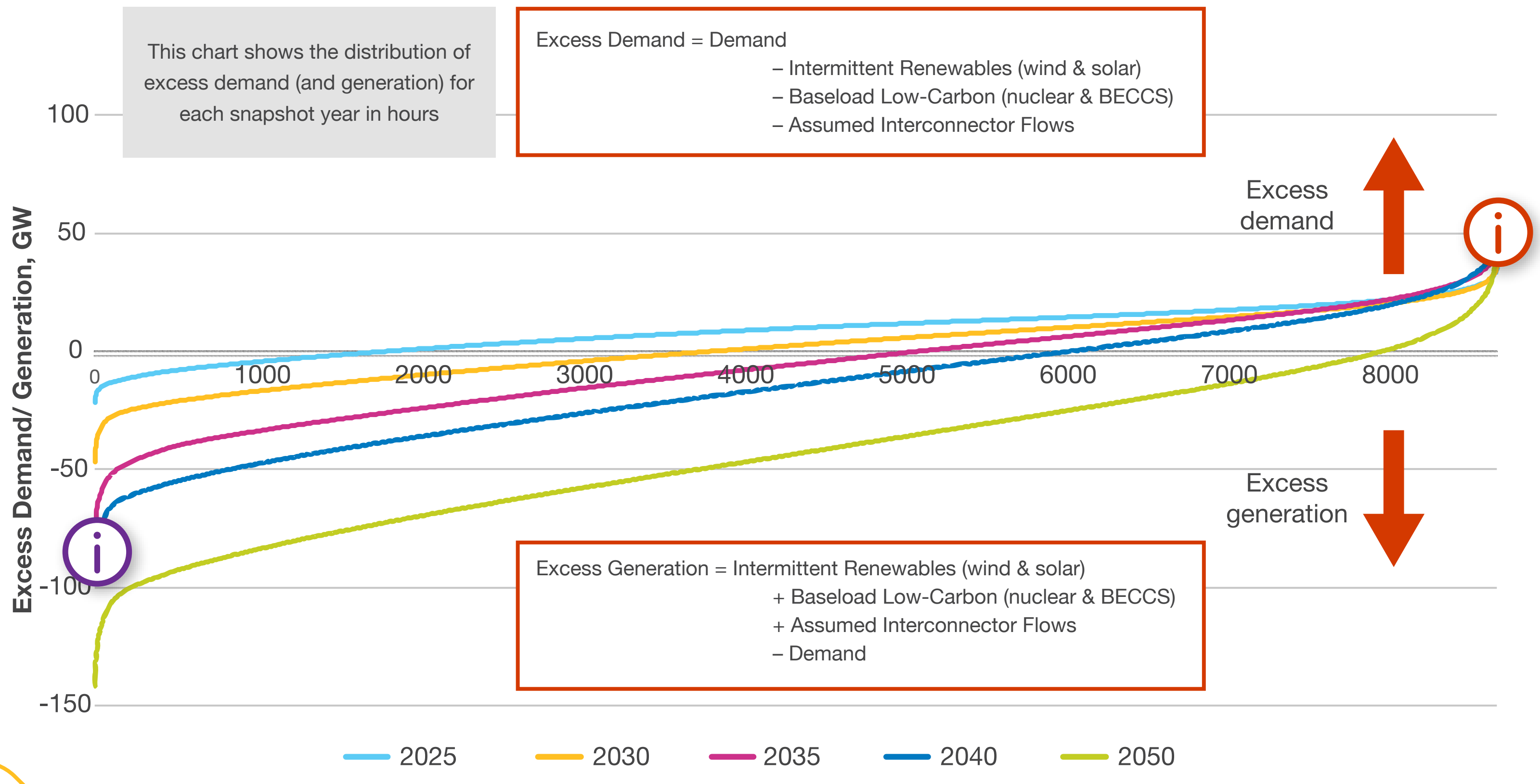
**While adequacy focuses on the periods where there is insufficient generation to meet demand, it will be increasingly necessary to consider adequacy in the context of developing the right markets, the right networks and future operability challenges to be confident that we can ensure adequacy in a cost effective way.**

For example, while different portfolios of resources may provide similar levels of adequacy, the operability impacts of each may be different. A resource mix with high levels of renewables combined with less flexible generation, will have much more surplus energy throughout the year. This will mean that there will be a higher level of renewable curtailment to ensure the supply/demand balance.

While this over supply of energy is not a security of supply issue, it can increase operational costs significantly. Therefore, we think that managing this over supply of energy will be the next big operational challenge that we are working to find solutions to manage.

The Leading the Way scenario has a high penetration of renewables and nuclear in the generation mix. The chart shows the supply of generation versus demand out to 2050. It shows that in 2035 the pink line crosses the x-axis at roughly 5000 hours. This means that there will be excess energy for more than half the year.

### Excess Demand/Generation Distribution (GW): Leading the Way

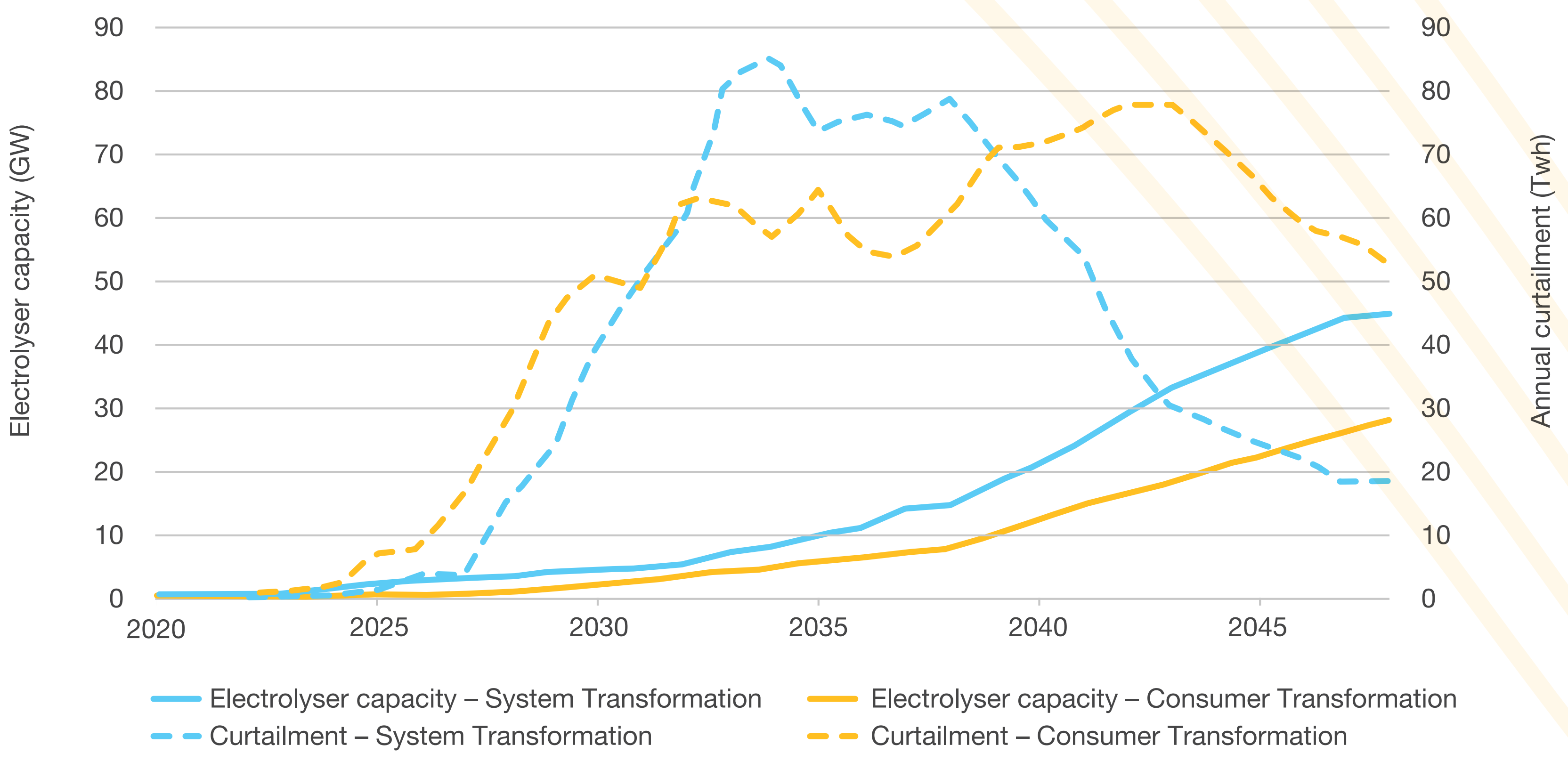


# Adequacy

**This excess energy, or over supply, can increase operational costs unless ways are found to use the excess energy other than curtailing it.**

This chart shows the build out of electrolyser capacity against the energy curtailed in two FES scenarios. As is evident, there is a considerable amount of curtailment especially between 2030 and 2040. Our identification of the system needs for over supply is still in its early stages and will develop through future versions of the OSR.

## Electrolyser capacity and curtailment




Operability Strategy Report / Balancing the System / 91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