Operability Strategy Report

December 2021

nationalgridESO

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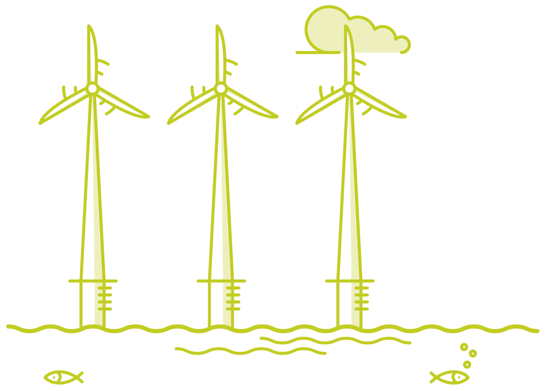

Executive summary

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 meet these challenges.

We continue to work closely with our stakeholders to ensure a holistic approach that looks across systems, markets, policy, technology and innovation as we develop and deliver solutions in response to those challenges. Collaboration and co-creation are at the heart of our approach and throughout this report we highlight opportunities for engagement, and signpost where to look for more information.

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 our future system needs, while the Markets Roadmap explains how our markets are evolving to meet these future needs in the most efficient way.

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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 DNO/DSO transition and the growth of Distributed Energy Resources (DER) and interconnection. By 2030 we expect to see 40GW of offshore wind and 17GW of interconnection, both of which will present operability challenges. 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 end consumers.

By 2025, we will have transformed the operation of Great Britain's electricity system and put in place the innovative systems, products and services to make sure that the transmission system is ready to handle 100% zero carbon electricity. But it doesn't stop there and 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.

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Executive summary

Key messages

As in previous editions of this report, we consider operability challenges in five key areas of Frequency, Stability, Voltage, Thermal and Restoration. In each area we explain the operability challenges, describe the capabilities we need to meet our requirements, and look forward to anticipate the next challenge. Our plans will deliver the services we need to operate a zero carbon network and remove our reliance on fossil fuelled generation. A short summary of our key messages for each operability area is provided on the following pages, with links to the relevant chapters for further detail.

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Executive summary

1 Frequency

System inertia is reducing and this, combined with increased variation in supply and demand, means that system frequency is more volatile and more unpredictable. This requires a step change in how we manage frequency through both our response and reserve services.

- **Response** – we need pre-fault services to manage frequency close to 50 Hz and post fault services to ensure we can contain the frequency following a fault. In a system with lower inertia, we need post fault services to be faster to ensure that the frequency is contained.
- **Reserve** – is manually activated and can be used to move frequency back towards 50Hz following the activation of response. Our new reserve services need to work seamlessly with the new suite of response services and their characteristics and sizing are driven by code and license obligations that describe how frequency is to be managed.

The size of our frequency requirements are driven by the inertia levels on the system and the size of both generation and demand losses. These requirements may change and will be heavily impacted by how the system evolves. For example, our requirements increase if system inertia falls further or if there is a drive towards tighter frequency standards. The table below sets out our 2025 requirement and assumes the inertia provided by the market falls as low as 96GVA.s:

Frequency service	System need	Requirement
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 to the statutory range (+/-0.5Hz) within 60 seconds	up to 1,400MW
Slow Reserve	**Restore** frequency to the operational range (+/-0.2Hz) within 15 minutes	up to 1,400MW

To date, our frequency control strategy is based around the need to contain and recover from sudden unplanned faults. However, the next big challenge may be around managing system imbalance during normal operation, as system imbalance grows to be more variable due to less predictable supply and demand patterns.

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Executive summary

2 Stability

Stability has traditionally been supplied as an inherent by-product of synchronous generation. However, the increase of inverter-based technologies such as wind and solar continue to drive a decline in this inherent stability of the system. We fill this gap by synchronising CCGTs and biomass generators, but 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.

System inertia is one of the key components of stability and our requirement for system inertia is significantly impacted by the changing system conditions relating to the growth of non-synchronous generation, displacing those that have historically provided inertia. In addition, new larger assets of up to 1.8GW are connecting to the system, increasing our largest loss on the system. To secure for this loss and ensure the Rate of Change of Frequency (RoCoF) remains less than 0.5Hz, we need to have sufficient levels of inertia available so that the system remains stable in the event of a fault. The combination of these trends increases our requirements and these changes across the system are set to continue.

To manage zero carbon operation we know that we will need a minimum of 96 GVAs of inertia to ensure system stability can be maintained in the event of a significant loss and that the frequency does not fall too low. Our Dynamic Containment (DC) product currently helps to stabilise frequency variations and the implementation of faster frequency services in the future could reduce the inertia requirement further.

Across all FES scenarios, there is a notable and continuous decline in inertia provision to the market. We are currently procuring inertia to meet this forecasted shortfall through phases 1, 2 and 3 of our Stability Pathfinders. The combination of the volumes procured through these Pathfinders means that we can meet our inertia requirement of 96GVAs until 2027. We continue to forecast our future requirements beyond 2027 to ensure we have sufficient capability on the system to meet our needs. We know that from 2027 our requirement will increase, and we continue to explore options for meeting this requirement beyond 2027.

Operating the system with low inertia will continue to represent a key operational challenge into the future and we will need to ensure we improve our understanding of the challenges this will bring. In 2021 we launched our first-of-its-kind inertia monitoring system, providing control room engineers with real time inertia for the next 24 hours. The use of instantaneous data rather than operational forecasts, means that we can continue to optimise how we manage inertia and system stability in future.

To fully understand the impact of increasing converter-based technologies on the system, we will need to have accurate modelling capabilities of both the network and its users. There are several innovation projects underway which focus on detailed electro-magnetic transient (EMT) studies to help us further understand the impacts of increasingly concentrated areas of generation connected to the system via power electronics.

In addition, we also have a Stability Market Design Innovation project underway which is considering current GB stability arrangements and investigating the best option for an end-to-end stability market design in the future.

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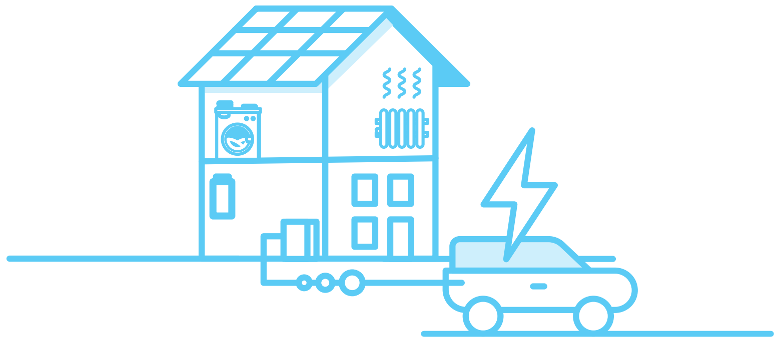
3 Voltage

Voltage levels are managed through the injection and absorption of reactive power. Maintaining voltage levels across the transmission network has become increasingly more challenging as decreasing reactive power demand on distribution networks and reducing power flows across the transmission network are driving an increasing need to absorb reactive power on the transmission system. The closure of coal and gas fired power stations is reducing the available reactive power capacity. In addition, the reduced running hours of these power stations means that we have to synchronise them to access their reactive power capacity, which increases balancing costs.

Our latest Voltage Screening Report (June 2021) has highlighted numerous areas where there is reducing reactive capacity, or a reactive need to reduce balancing costs. Across seven regions we will lose access to 3,600MVAr of reactive capacity by 2025, and an additional 1,000MVAr by 2030, through plant closures. We will need an additional 1,600MVAr of reactive power absorption by 2025 to manage voltage levels within the required limits. This volume is largely needed across the middle to south of England. Further work is planned which will identify the reactive power requirements out to 2030.

Our voltage pathfinders are identifying new providers of reactive power services, helping us meet some of our locational operational needs out to 2034, and contributing to our 2025 zero carbon ambition. We are also working to investigate the appropriateness of a reactive power market which could help increase access to reactive power capability, both on transmission and distribution networks.

Looking forward, the message within our voltage screening report 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. Our next big challenge is to overcome the challenges of accessing reactive power from distribution connected assets. As the volume of embedded generation continues to grow, accessing reactive power capability on these assets is key to managing transmission network voltage levels. We will also continue to work with the distribution network operators to understand how the growth of electric vehicles and heat pumps will affect reactive power demand, and how we will efficiently manage the transfer of reactive power between the distribution and transmission networks.



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4 Thermal

We manage the flow of electricity across the high voltage transmission system from where it is generated to where it is consumed. The assets which transport this energy around the network have physical limitations on how much power can be carried. We must prevent these limits being reached or exceeded to prevent loss of supply to areas of the network. The majority of our current constraint management actions involve the redispatch of generation. We are mindful of the impact these actions have from both a carbon and cost perspective and we are proactively focused on seeking innovative solutions to manage these constraints.

Our electricity ten year statement (ETYS), published in November 2021, shows that thermal constraint costs are likely to increase due to high flows on the transmission system in the next ten years. This increase is driven by significant growth in renewable generation expected to connect in Scotland, northern England and offshore, and further growth in continental interconnectors in the south. By 2030 some areas of the network will see peak power flows which are 400% greater than current boundary capability. We cannot manage these boundaries by redispatching generation alone. Article 13 of the Recast Energy Regulation requires us to limit the redispatch of renewable and high-efficiency cogeneration to 5%, and analysis from the Network Options Assessment (NOA) shows that we are likely to exceed this threshold before 2025. Our constraint five point plan is seeking to mitigate the volume of redispatch by intertripping generation, further optimising outage patterns by improving constraint cost forecasting, and finding ways to enhance existing network assets.

Between 2025 and 2030, the NOA forecasts that generation from renewables will exceed 50% of total demand, meaning the 5% threshold will no longer apply. However, the cost of redispatch is expected to rise significantly ahead of major network reinforcement. The constraint five point plan and commercial solutions in the NOA both seek to mitigate these rising costs. Our first commercial solution is the constraint management pathfinder which will deliver an intertrip scheme on the B6 (Scotland-England) boundary from October 2023.

Beyond 2030, the NOA recommends optimal network reinforcements which increase capacity to facilitate the growth in generation. Where residual constraints remain, or timescales prevent network reinforcement, commercial solutions are a potential option.

Going forward, growth of flexible resources will enable greater use of commercial solutions to manage transmission constraints as an alternative to large reinforcements. The Offshore Transmission Network Review may also deliver constraint cost benefits by increasing network capacity through coordinated connections. Distribution network solutions will provide further options for managing transmission constraints. This approach is currently being developed and tested through our Regional Development Programmes with a view to rolling out this functionality more widely in the longer term.

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5 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, transmission connected fossil fuel generators to provide restoration services. The decline in this traditional generation mix and the increasing penetration of distributed energy resources (DER) means that we need to ensure restoration services can be provided by a range of users in the future.

By the mid-2020s, we aim to be running a fully competitive restoration procurement process with submissions from a wide range of technologies connected at different voltage levels on the network, with Transmission Owners (TO) and Distribution Network Operators (DNO) playing a more active role in the restoration approach.

The Grid Code has always required us to have the capability to restore the system, but had limited detail as to what that entailed. 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.

Implementing the ESRS will involve the creation of various industry working groups to ensure we consider all elements of the requirements, including future network needs and communication and infrastructure requirements for delivery of effective restoration services.

Through our Distributed Restart innovation project, we have been working with industry to facilitate the provision of restoration services from distributed energy resources. The project is due to complete in March 2022 and successful trials have been completed, demonstrating the capability that can be provided by DER in future. In October 2022 we plan to begin a competitive procurement event for restoration services in the Northern zones (Scotland, NE & NW). This will focus on services from Distributed Restart and marks the start of increased competition and reduced costs in the procurement of restoration services. We will continuously refine this procurement process to ensure we have sufficient capability of restoration services across a range of provides by 2030.

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ESO Publications

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.

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How to get involved

How to get involved

We want to work with you!

Your support and input is vital if we are to deliver on our ambition to operate a zero carbon electricity system in 2025.

Throughout the main body of our report you will find links to specific opportunities to get involved in all key areas of our work. Please feedback on our approach to meeting operability challenges 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 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.
nationalgrideso.com/research-publications/system-operability-framework-sof

Reports	Overview	When to expect
Provision of Short Circuit Level Data	As more renewable generation is connected to the GB Transmission System the modelling of Short Circuit Level is becoming more complicated. This paper will provide a description of what SCL data have already been provided to the industry, the potential options for further data provision, and the feedback gathered through engagement with the industry on these issues.	Dec 2021
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. This report will look at changes to the power quality on the electricity network.	Mar 2022

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Zero Carbon Operability

Zero Carbon Operability

Great Britain has the fastest decarbonising electricity system in the world and as the system operator we have an ambition to operate 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 pathfinders and voltage pathfinders reduce our reliance on fossil fuelled generation for critical transmission system services. We can already maintain our system restoration capability without warming or running fossil fuelled plant.

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:

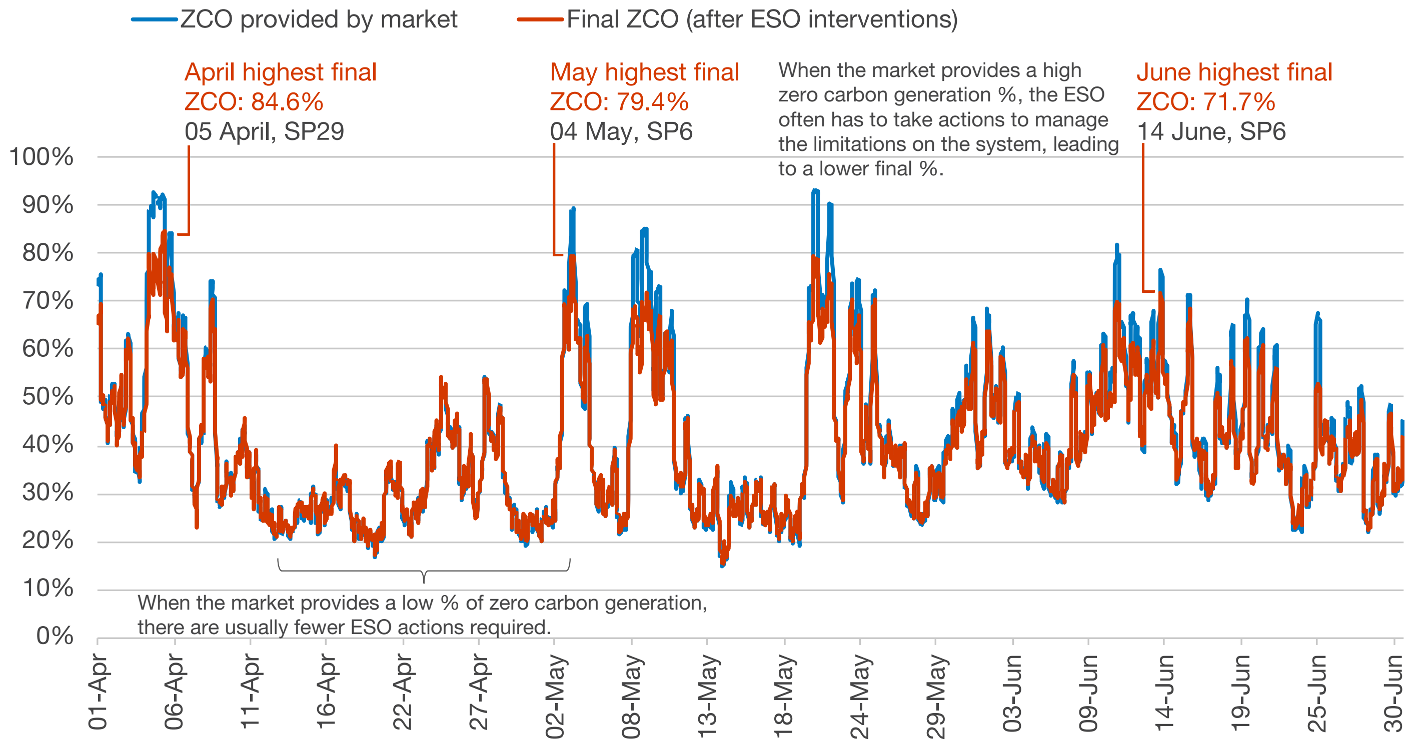
$$\text{ZCO(\%)} = \frac{\text{(Zero carbon transmission connected generation)}}{\text{(Total transmission connected generation)}} \times 100$$

The highest ZCO figure so far this year was on 5 April in settlement period 29 where 85% of transmission generation was zero carbon after our operational interventions. The value was high because it was cold (hence demand was high) and there was high renewable output.

Values for May to September were lower because the demand was reduced due to the warmer weather. When the demand is low but renewable output is high, the ZCO after ESO actions is often lower. This is because we take actions to manage operability constraints, and these actions represent a larger proportion of the overall amount of generation.

High ZCO values typically correlate with lower wind output, the low wind spells during most of April and the start of May have a ZCO around 30%.

Q1 ZCO detail by Settlement Period



Q1 Q2

Zero Carbon Operability

We forecast that the maximum ZCO the system can currently accommodate is between 80%-85%. This is in line with what we have seen in 2021. ZCO will be 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 remove zero carbon generation and add on carbon-producing generation such as CCGT or biomass to meet our response, inertia and voltage requirements.

By 2023 the maximum ZCO limit rises to 85% - 90%. This increase is due to the work we are doing. For example, our new response products, the stability pathfinders, the Accelerated Loss of Mains Change Programme, the implementation of the Frequency Risk and Control 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.

More information on our zero carbon progress can be found on our 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.

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Frequency

Frequency

Summary

Our frequency control strategy is achieved through the use of two types of service; frequency response and reserve. Frequency response services are activated automatically 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 system event or proactively in anticipation of a system need. Just like response, reserve can deliver either an increase or decrease in active power and can be provided by either a source of generation or a source of demand.

The basic aim of our frequency control strategy, and the services we employ is to maintain system frequency at the target of 50Hz. As well as maintaining 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 report we look at our frequency control obligations and how these translate into requirements for response and reserve. We also look at factors that might influence or change our requirements between today and 2025.

What do we mean by Frequency?

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

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Frequency

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

1. Regulation and containment

The obligation on the ESO to control frequency can be understood in two settings:

- Pre-fault or steady-state
- Post-fault or transient frequency deviations

The SQSS is the legal document that describes to what extent we should control frequency. It requires that we operate the network and avoid 'unacceptable frequency conditions' in a number of events.

These unacceptable conditions are defined for each of the settings above as:

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

The first of these requirements states that we should regulate frequency to +/-0.5Hz of the 50Hz target in normal conditions.

The second seeks to oblige us to limit the impact of faults on the system frequency, this can be described as post-fault containment.

Post fault containment

Our obligation is to contain transient frequency deviations to within +/-0.5Hz of 50Hz for **events** unless these deviations are infrequent and **tolerable**.

Whether such frequency deviations are **tolerable** depends on the combination of three factors:

- How often they occur (likelihood)
- How long they last for (duration)
- How large they are (deviation)

The table below illustrates the combination of these factors as concluded by the 2021 FRCR

#	Deviation	Duration	Likelihood
H1	50.5> Hz	Any	1-in-1,100 years
L1	49.2≤ Hz <49.5	Up to 60 seconds	2 times per year
L2	48.8 < Hz 49.2	Any	1-in 22 years
L3	47.75 < Hz ≤ 48.8	Any	1-in-270 years

Any frequency deviation above 50.5Hz would not be tolerable unless caused by a fault only likely to occur at most once in 1,100 years.

A deviation that takes frequency down to between 49.2Hz and 49.5Hz would be tolerable if it lasted up to 60 seconds and was caused by an event with a likelihood of at most twice per year.

A deviation down to as low as 47.75Hz would be tolerable if caused by an event that was only likely to occur at most once in 270 years.

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Frequency

The FRCR also defines the **events** for which unacceptable frequency conditions should not occur. The FRCR process will be reviewed yearly, in the first issue the events studied fall into three categories:

BMU-only an event that disconnects one or more BMUs, and may or may not also cause a consequential RoCoF loss (No Vector Shift loss)

VS-only an event that causes a consequential Vector Shift (VS) loss and may or may not also cause a consequential RoCoF loss (no BMU loss)

BMU+VS an event that disconnects one or more BMUs and causes a consequential VS loss, and may or may not also cause a consequential RoCoF loss

And thus via the FRCR the ESO and wider stakeholders can be informed 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.

Steady state regulation

The other obligations from the SQSS relate to regulating frequency in normal, or steady-state conditions.

The system frequency is moved away from the target of 50Hz not just by sudden, unexpected faults but also by gradual demand & supply imbalances and independent generator actions. For this reason we use services to regulate the frequency pre-fault.

The obligation from the SQSS is that we should keep steady-state frequency to within the standard frequency range of 50Hz +/-0.5Hz.

The next two charts illustrate how demand and supply imbalances can drive the need for frequency regulation services, both automatic (response) and manual (reserve).

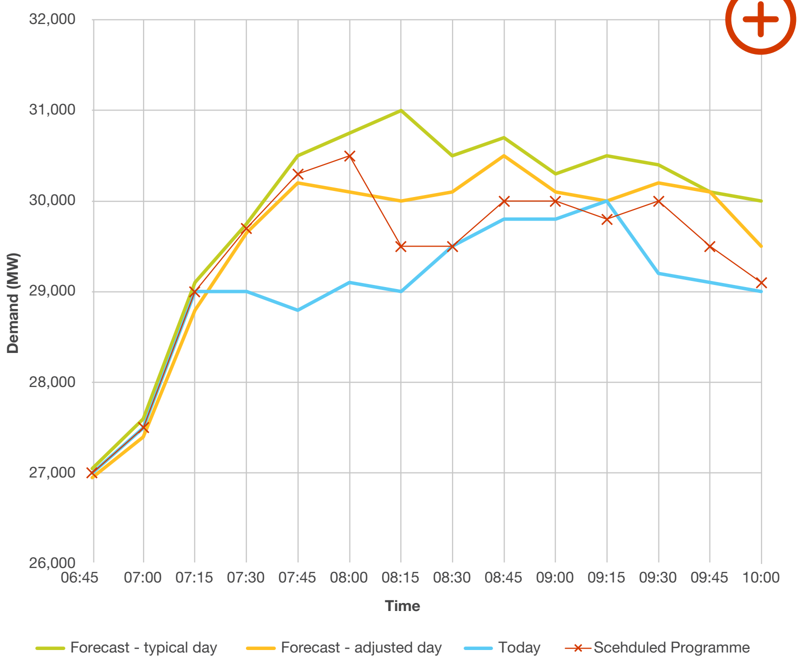
The image to the right is an illustration from a real-world experience. The yellow and green lines were the forecasts of how demand may change over the course of the ~3hr period. The blue line records the demand outturn.

On this occasion there was a significant difference between forecast and outturn demand.

The red line is the outturn generation programme – showing the final generation as scheduled by the control room.

The example highlights the uncertainty and challenge faced by the control room. Demand did not evolve as expected, and as a result the planned generation programme had to be significantly altered in real-time.

Demand Predictor



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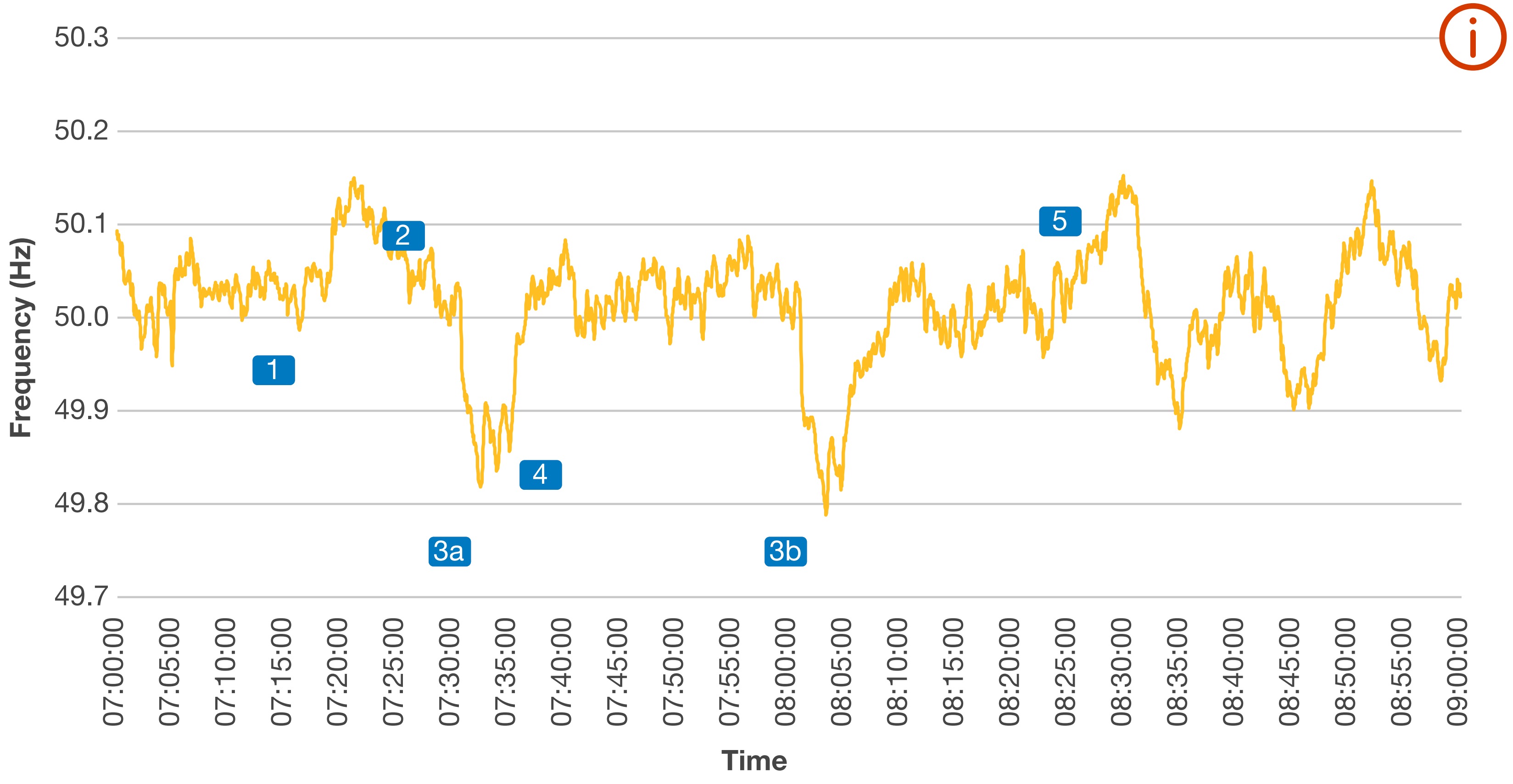
Frequency

The chart below shows the system frequency over the same time.
Looking at the two charts we can piece together events, actions, and consequences.

System frequency



Active throughout the example above, and indeed at all times, are automatic frequency regulation services. These services are designed to help us meet the steady-state regulation obligation. As the example showed, we will often take additional manual actions to regulate frequency.

We are required to regulate frequency as per the SQSS and avoid steady-state frequency moving outside of 49.5Hz or 50.5Hz – the statutory range. The next section covers the rules and obligations that come into play when frequency moves outside of the statutory range and the narrower operational range.

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Frequency

2. Recovery and restoration

The SOGL describes the obligations on all system operators in Europe, and these obligations are now part of UK law. The obligations vary across the four synchronous areas but follow the same principles.

- A maximum time to recover frequency
- A maximum time to restore frequency

For GB the obligations are:

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

Frequency quality defining parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
Standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
Maximum instantaneous frequency deviation	800 mHz	800 mHz	1000 mHz	1000 mHz
Maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
Time to recover frequency	not used	**1 minute**	1 minute	not used
Frequency recovery range	not used	± 500 mHz	± 500 mHz	not used
Time to restore frequency	15 minutes	**15 minutes**	15 minutes	15 minutes
Frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
Alert state trigger time	5 minutes	10 minutes	10 minutes	5 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.

We can now consider the obligations above in the wider context of the operating environment and the operability challenges.

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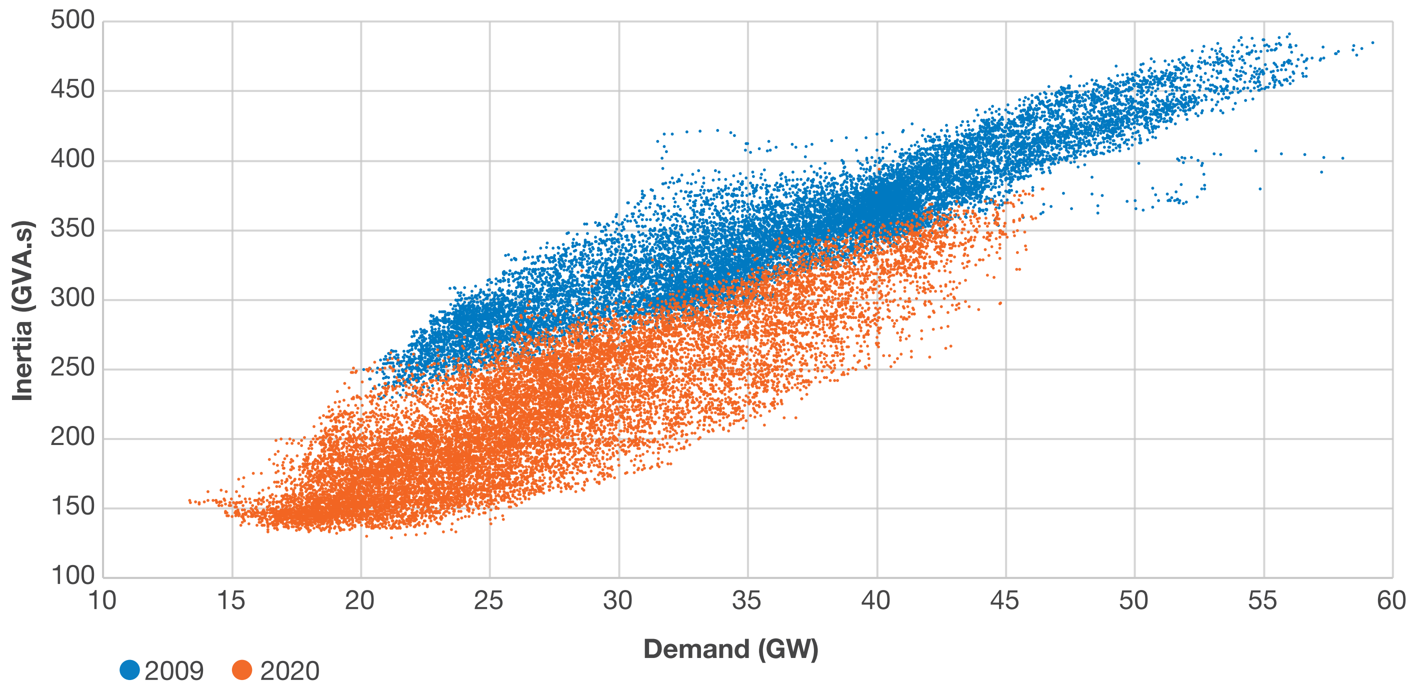
Frequency

Falling inertia

- In the last decade the average annual inertia has fallen by around 40%. This is not a new phenomenon and previous issues of the OSR have explained the impact this has on operability. Lower inertia means that system frequency is less resistant to change, it will change more quickly when subject to a shock, like a sudden loss of generation or demand.
- Today our policy is to operate with a minimum inertia of 140GVA.s. The four pathways to net zero in 2050 that have been studied in the FES indicate that this may become more challenging. All the pathways anticipate a further fall in inertia. The minimum inertia policy is one potential area that FRCR can investigate to see if a different approach would provide better value vs risk.

Inertia vs Demand



Inertia vs Demand

Annual Distribution of System Inertia

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Frequency

Increasing loss sizes

- Generation and demand providers of many different sizes are connected to the network. We often focus on the largest of these because if and when they trip they cause the biggest challenges. The bigger the loss the more actions we need to take, both to protect before an event and to recover post an event.
- Today the North Sea Link interconnector can be either the largest generation or demand loss as it is capable of imports and exports of 1400MW. The maximum loss will change as new nuclear and interconnectors connect to the network.

Operating conditions

- The combination of low inertia and large losses means that RoCoF can be high. 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 and launch dynamic containment, a fast-acting frequency response service.
- Dynamic Containment is the first of a suite of new response and reserve services. All these services contribute in some way to mitigating the risks that arise in the low inertia system we expect to operate in the future.

2021	2023	2024	2024	2027
North Sea Link @ 1400MW	**Viking** @ 1400MW	**NeuConnect** @ 1400MW	**Gridlink** @ 1400MW	**Hinkley Point C** @ 1800MW

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Frequency

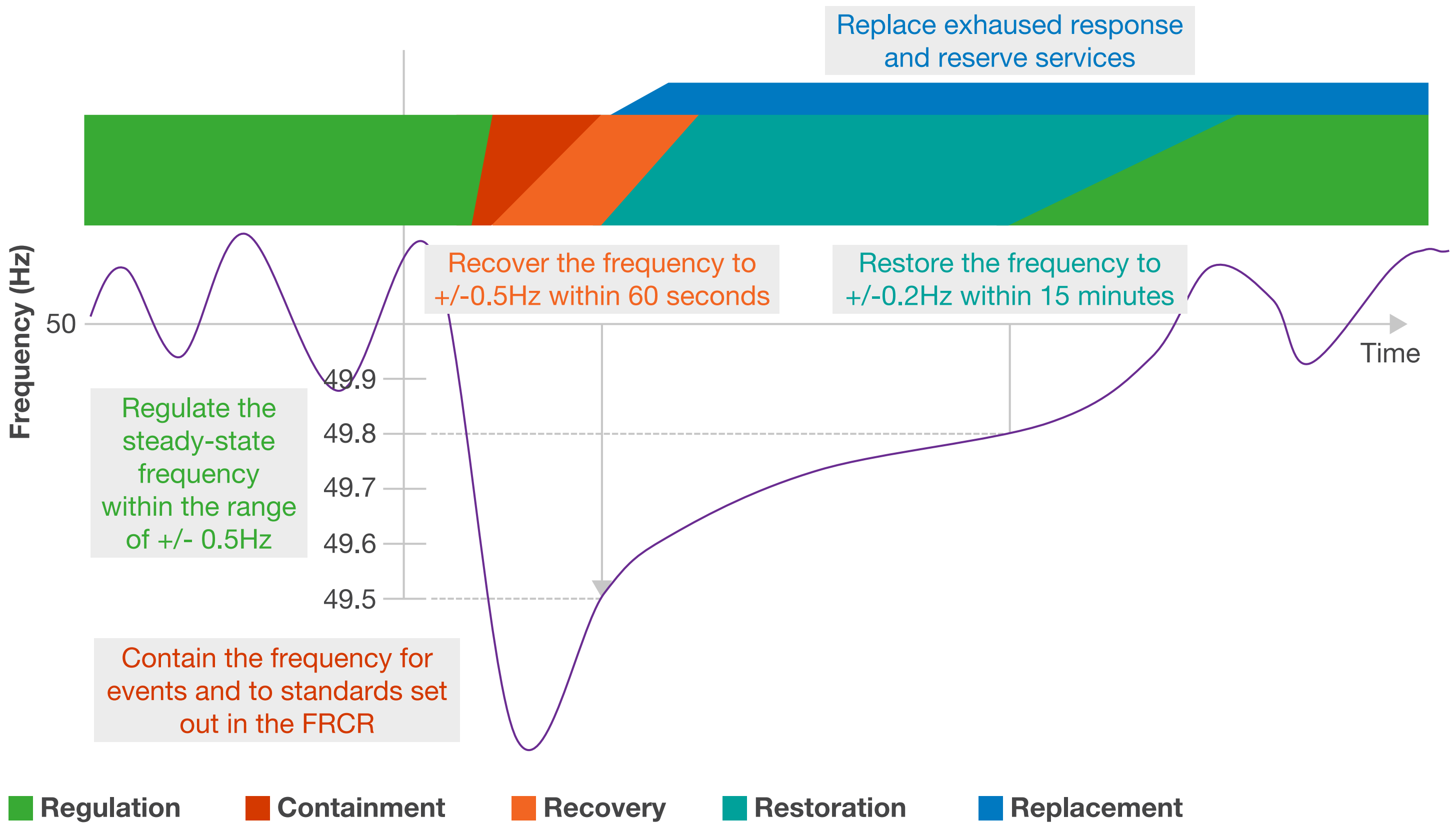
What capability do we need to meet these operability challenges?

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

1. We must **regulate** steady-state frequency within the statutory limits of +/-0.5Hz
2. We must **contain** the frequency for events and to the standards set out in the FRCR
3. We must **recover** frequency to the statutory range (+/-0.5Hz) within 60 seconds
4. We must **restore** frequency to the operational range (+/-0.2Hz) within 15 minutes
5. We can then use reserves to **replace** any energy imbalance

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



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Frequency

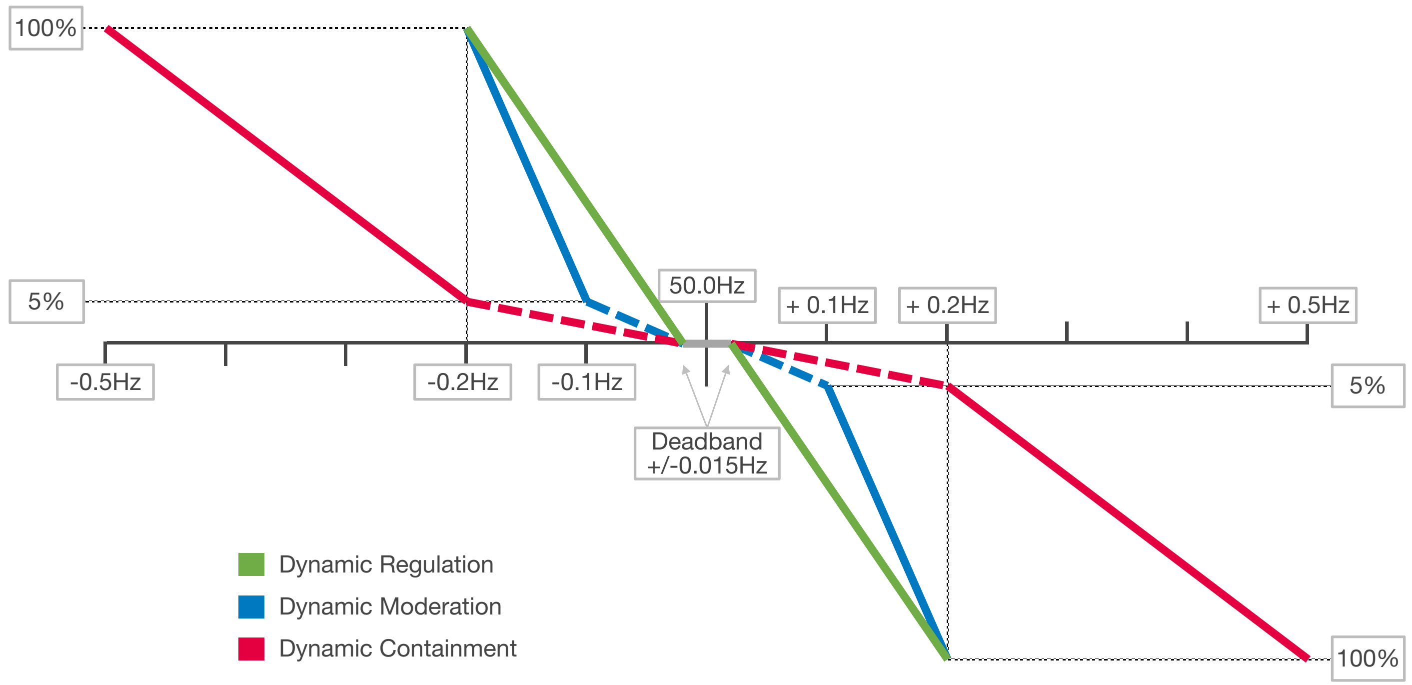
What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

Regulate

- Frequency regulation in steady-state pre-fault conditions will be met by a combination of Dynamic Regulation and Dynamic Moderation. Both these services are expected to be launched in 2022.
- We expect to buy 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.

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 will determine 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 1400MW losses. If a larger loss connects, such as Hinkley Point C we may need to buy more.



Interaction between containment and regulation services

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Frequency

Recover

- Our principle recovery service will be Quick Reserve, a new service to be launched by 2023.
- The requirement for recovery services is also driven by the size of potential loss to manage. Therefore we expect to buy up to 1400MW of Quick Reserve by 2025.

Restore

- Our principle restoration service is Short-Term Operating Reserve (STOR) which will transition into the new Slow Reserve service planned for launch in 2022.
- Frequency restoration services will be sized similarly to recovery services, by 2025 we could buy up to 1400MW of Slow Reserve. 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.

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Frequency

How do the requirements change under differing Future Energy Scenarios?

- The requirements in the previous section are based on what we know today about when and how new connections are joining the network.
- The requirements also assume that there is no fundamental change to our policy. The FRCR may run every year and could, for example, recommend a change to the type of loss that we need to secure. The SQSS may similarly be reviewed and modify the standards to which we must manage frequency.
- A key driver of response requirements is the level of inertia. If the same frequency standards are to be met then higher inertia systems need less frequency response while low inertia systems require more and faster frequency response.
- The proportion of weather-dependent generation will also impact our requirements. Scenarios with more intermittent, non-dispatchable generation are likely to require more reserves.

Factors that can **increase** response & reserve requirements	Factors that can **decrease** response & reserve requirements
Tighter frequency standards driving towards lower risk	More relaxed frequency standards driving towards lower cost
Lower inertia	Higher inertia
Larger demand or generation losses	Smaller demand or generation losses
More uncertainty and error between forecasts and out turn (both generation and demand)	Less uncertainty and error between forecasts and outturn (both generation and demand)

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Frequency

What is the next big operational challenge?

To date our frequency control strategy is based around the need to contain and recover from sudden, unplanned faults. This is a consequence of the market and operating conditions we have faced; a high number of very large generators that can cease generating very rapidly and without warning.

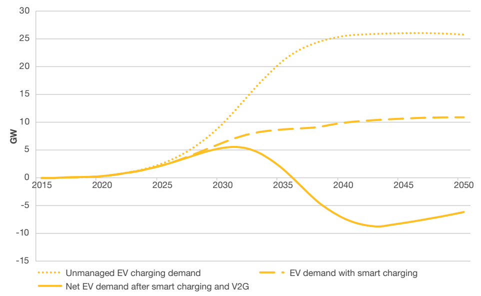
On the path to net zero our system may experience greater variation in pre-fault imbalance, this will come from several areas:

- Domestic demand flexibility, like smart appliances and EV charging
- Commercial and industrial demand flexibility, like greater price sensitivity and electrolysis
- More weather dependent and intermittent generation
- Growth in interconnection to neighbour markets leading to periods of rapid ramping

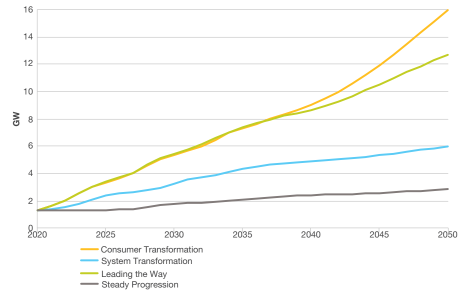
At the moment we manage imbalance by taking actions in the balancing mechanism but in the future we may need to adapt our approach and tools:

- Greater visibility of all sources of flexibility
- More efficient control of the very high number of flexible assets
- Greater automation of actions
- New services to value and incentivise the types of flexibility and capability that we need
- Better forecasting of all the new sources of demand and generation

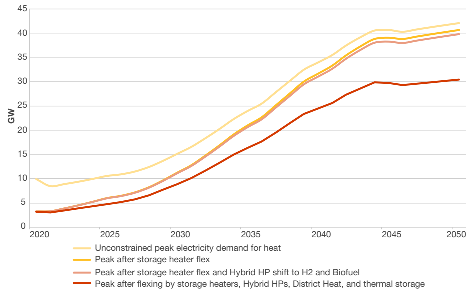
Electric vehicle charging behaviour at ACS winter peak system demand



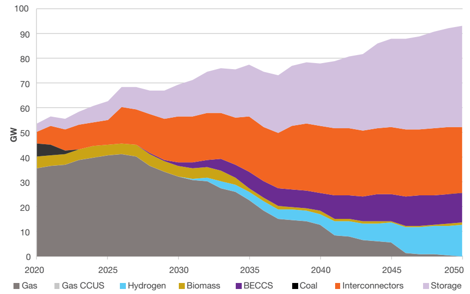
Industrial and commercial demand side response from heat



Residential winter peak electricity demand for heating and flexibility from heating technologies



Dispatchable electricity supply sources Consumer Transformation



Click to enlarge charts

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Stability

Stability

Summary

The reduction in running of synchronous generation and the increase of conventional inverter-based technologies continue to drive a decline in the inherent stability of the system.

We need to introduce alternative capability, potentially through technologies such as synchronous units, which can provide stability separately from power or non-synchronous units which 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.

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Stability

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

Rotating generators produce power at the same frequency as the system frequency and are called synchronous generators. Coal, gas, biomass and nuclear generators are examples of synchronous generation. Wind and solar are examples of non-synchronous generation as they are connected to the system through power electronics. When a synchronous generator is running it has an inherent stabilising effect on the system in most circumstances. Non-synchronous generators do not have the same inherent stabilising effect.

As we move to a low carbon electricity system, more of our power is coming from renewable sources which are generally non-synchronous. This is leading to a reduction in the inherent stability on the system. To support the transition to a low carbon electricity system we need to both decrease our reliance on fossil fuel generation to stabilise the system and learn to operate a more dynamic system.

The 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 listed below:

- **Inertia** – is a characteristic of the system that defines how much energy is available in the rotating masses of all machines (generators and motors) that are directly coupled to the system. The inertia enables the instantaneous balancing of any surplus or deficit in power. The rate at which frequency changes following a loss of generation or demand depends on the total system inertia.
- **Short Circuit Level (SCL)** – is related to the amount of current that will flow on the system during a fault. During the fault the system sees a low impedance path to the location of the fault and the current flows from all sources into it. SCL is also used as a description of the strength of the system. When SCL is high the system is strong, whereas when SCL is low we say the system is weak.
- **Dynamic voltage** – is a measure of how the voltage changes and recovers on the system following the clearance of a fault.
- **Loss of Mains (LoM) protection** – a key operability risk on the system is the disconnection of embedded generation due to over sensitive loss of mains protection. Loss of mains protection checks whether generators are still connected to the main network in the event of a fault and will disconnect this generation to prevent damage to equipment and in the interest of safety. Historic standards for this type of protection are no longer suitable for a system with increasing levels of non-synchronous generation. Accelerated Loss of Mains Change Programme (ALoMCP) offers funding to distributed generators to upgrade their hardware, improving network resilience to meet our net zero targets.
- **Fault Ride Through** – it is essential that assets connected to the system can remain connected following a fault on the system otherwise a minor fault could proliferate into a major incident. Requirements are placed on connected parties through the Grid Code and as the system changes, these parties need to ensure that they can remain connected across a broader range of scenarios.

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Stability

What capability do we need to meet these operability challenges?

To meet the stability challenges, we need to find new sources of stabilising capability rather than relying on generation powered by fossil fuels. Some of the stability requirement will continue to be provided by synchronous plant available in the electricity market depending on how much nuclear, biomass, hydro and gas is running.

New sources of stability could come from new synchronous assets such as synchronous compensators which will provide stability with a minimal impact on the electricity market. In providing stability capability synchronous compensators require only a relatively small demand rather than needing to export large volumes of power.

The other new source is expected to be from non-synchronous plants which are either designed or adapted to provide grid forming capability. We have been working with the industry to ensure that the minimum requirements for grid forming capability are specified in the Grid Code Modification (GC0137), although this capability will not be a mandatory requirement.

We also need to ensure that the standards we apply to those assets connected to the system remain fit for purpose. Updating loss of mains standards and reinforcing fault ride through requirements are examples of where this approach has been necessary. Improving the information provided to industry on minimum short circuit levels to enable them to fulfil their obligations is another area which is currently under investigation.

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Stability

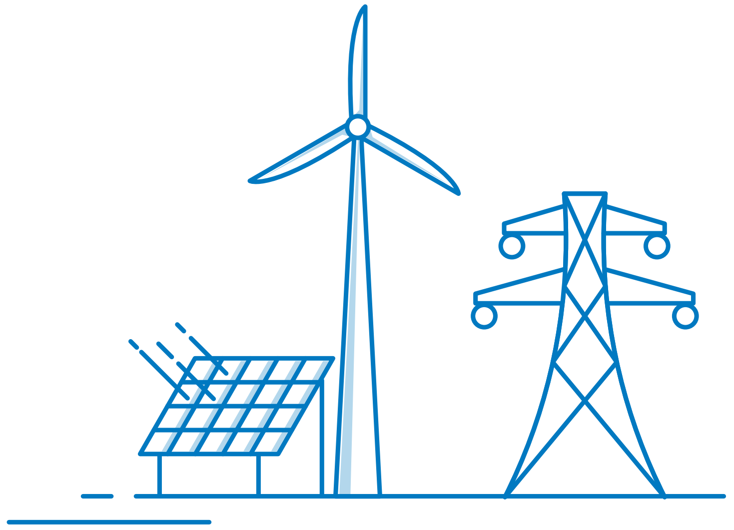
What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

Loss of mains protection

New standards for loss of mains protection come into force in September 2022. This will reduce the number of generators with inappropriate loss of mains protection settings and will reduce the volume of generation at risk of disconnecting in response to a large loss (and subsequent high rate of change of frequency) or electrical fault (and subsequent vector shift) on the system. This change will alleviate the Rate of Change of Frequency (RoCoF) and vector shift constraints, which have been the dominant factor when managing system inertia. In turn, this will reduce the cost of balancing the system and allow us to operate the system with lower levels of inertia which is a key step to enable zero carbon operation in 2025.

The process of changing protection is currently being managed through the Accelerated Loss of Mains Change Programme (ALoMCP). This project offers payment to generators to make the relevant changes to their assets. The cumulative total of approved applications through this programme so far is 6,856 sites, for a capacity of 12,423MW at a cost of £23.33m in payments to distributed generation owners. These numbers are updated on a quarterly basis after each application window and can be found in the ALoMCP Window Reports[1].

In April 2021 we submitted the first version of the Frequency Risk and Control Report (FRCR) which recommended allowing RoCoF losses to occur on the system when we had sufficient capability to secure them with frequency response. Prior to the implementation of FRCR 2021 Phase 2 in October 2021, the ESO was taking actions to maintain the system RoCoF below 0.125 Hz/s for credible losses to prevent the activation of RoCoF LoM protection. From October 2021 this restriction was lifted due to the increased volumes of fast acting response provided by the Dynamic Containment service. It is expected that distributed energy resources (DER) which do not meet requirements of the Distribution Code standards for September 2022 will be directly affected by events on the transmissions system. The ALoMCP will remain in place to ensure those units have a route to compliance prior to the deadline in September 2022.



1 www.nationalgrideso.com/industry-information/accelerated-loss-mains-change-programme-alomcp/key-documents

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Stability

Inertia

Today we ensure system inertia is always above 140GVA.s. Going forward minimum system inertia could be as low as 96GVA.s for zero carbon operation by 2025. Our studies indicate that if we have a 1.8GW largest loss on the system and we need to limit RoCoF to less than 0.5Hz, this means we need to keep inertia above 90GVAs. If we assume the largest loss on the system is ~6GVAs (corresponding to a 1800MW largest loss), this means our pre-fault inertia needs to be kept above 96GVAs.

Our future forecasts show that system inertia is likely to drop below this requirement in the next few years. This is part of the driver for the stability pathfinders as they are buying the system inertia needed to meet our requirement. Stability pathfinder phase 1 bought 12.5GVAs of inertia until 31 March 2026. Phase 2 will buy at least 6GVAs and phase 3 will buy at least 15GVAs. This means our requirement is fulfilled to at least 2027 based on our forecast of what will be provided through the energy market and pathfinders. Analysis from 2027 onwards highlights a potential increase in our stability requirement gap of up to 30GVA.s, although this varies across the different future energy scenarios.

We are currently investigating whether future inertia requirements are best solved through another pathfinder or through a stability market. A stability market innovation project 'Stability Market Design' will consider current GB stability arrangements and investigate the best option for an end-to-end stability design.

Short Circuit Level and Dynamic Voltage

Our requirement for Short Circuit Level (SCL) and dynamic voltage are set out in stability pathfinder phases 2 and 3. This requirement is regional in nature. Where short circuit levels are low, this is due to substantial amounts power electronics connected to the network such as interconnectors or offshore wind farms. This drives a regional requirement to increase short circuit fault level in these areas.

In the majority of areas, the solutions we procure for SCL will also meet the dynamic voltage requirement. In South Wales, we have identified that we have a requirement to ensure that the retained voltage during a fault remains to an acceptable level to enable generation to ride through the fault. Together with stability pathfinders phases 2 and 3, our operational requirements for SCL and dynamic voltage will be met up to the end of 2027.

To help facilitate those connected to the network in fulfilling their own obligations we also need to review the information we publish regarding SCL to give system users a better view of the minimum SCL on the network and how this is expected to change over time.

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Stability

Fault ride through

Similar to our requirement with accelerated loss of mains, our requirement for fault ride through is compliance driven. Non-compliance would introduce a potential risk to the system that would need mitigation, which would result in increased operational costs (likely through increased BM costs).

Forecasting capability

We also need to develop our capability to assess our stability requirements closer to real time.

We are installing two, first-of-their-kind, inertia monitoring systems to provide control engineers with real-time system inertia. In addition, one of these new tools includes the ability to look ahead to forecast inertia for the next 24 hours based on other operational forecasts. These will enable us to continue to optimise our approach to managing our inertia and stability requirements in future.

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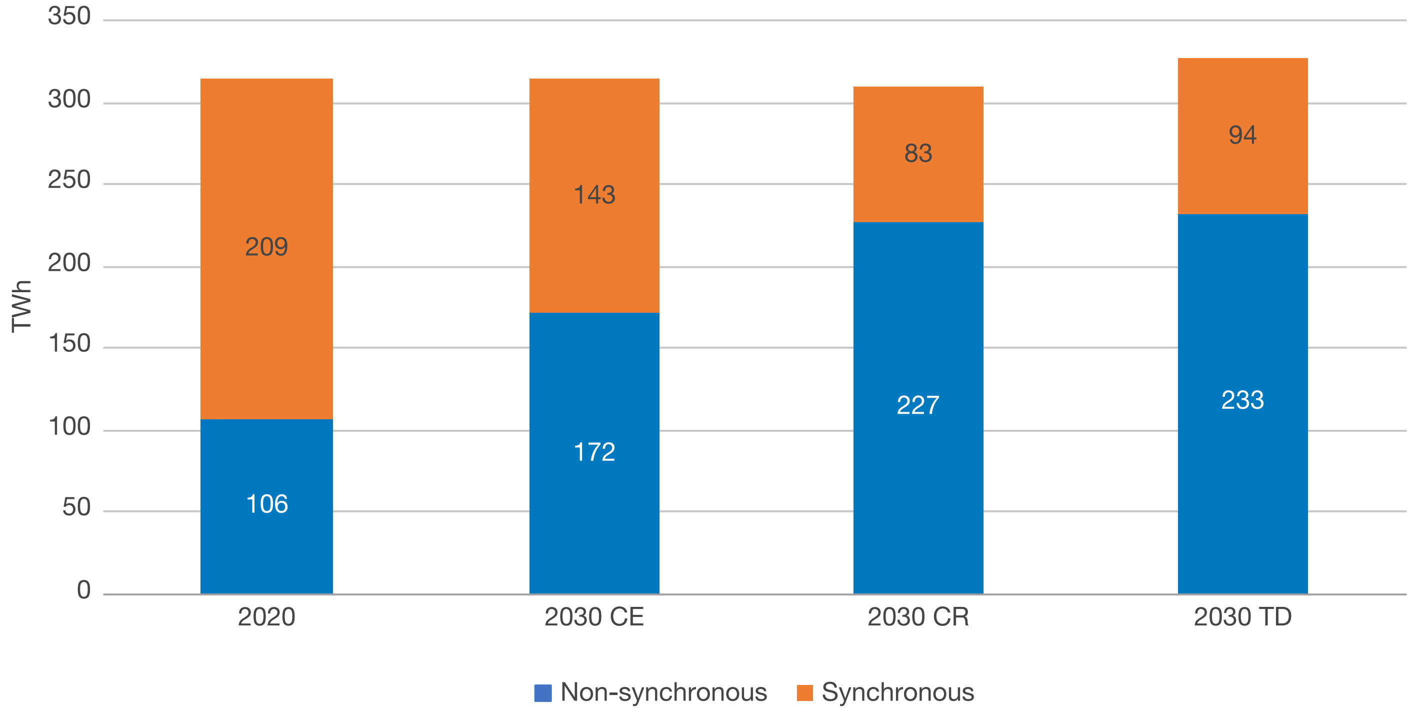
Stability

How do the requirements change under differing Future Energy Scenarios?

The volume of synchronous generation, the corresponding location on the system and the speed at which converter-based units are connected, drive the requirement for stability capability on the system. The requirement for our stability pathfinders was based on analysis of all four of the 2019 FES scenarios. Consumer evolution and consumer renewables both had a similar inertia requirement which was greater than the requirement in steady progression and two degrees. Looking ahead our future requirements remain higher in the consumer evolution and consumer renewable scenarios (of up to a maximum of 30GVAs) whereas there is no inertia requirement gap forecast in either steady progression or two degrees. We are currently in the process of refreshing this analysis using 2021 FES scenarios and expect this to be available by mid 2022. Our future procurement of stability services will ensure we optimise our requirements for effective zero carbon operation across all future scenarios. The two charts to the right demonstrate the growing penetration of non-synchronous generation across the different scenarios and the expected shortfall of inertia provision.

Growing penetration of non-synchronous generation (TWh)*



Growing penetration

Inertia Shortfall

*The figures provided in these charts do not include the volumes that will be procured through Stability Pathfinder phase 3.

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Stability

What is the next big operational challenge?

Our requirements for stability will continue to change as the system becomes further dominated by converter-based connections. To fully understand the impact of this on the operability of the system we need to ensure that we have accurate dynamic models of both the network and the users.

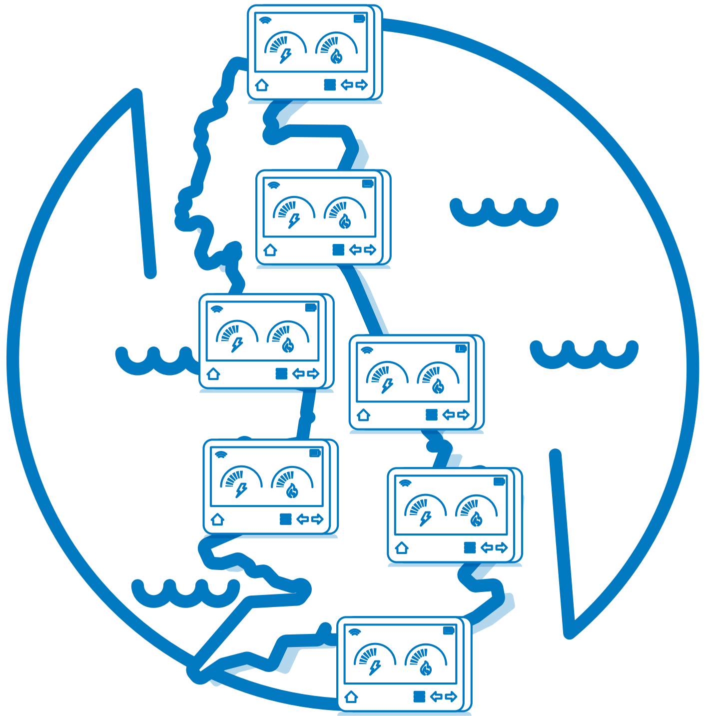
Power quality is critical to the performance of equipment connected to the electricity network. There is a direct correlation between power quality and system strength. The stronger the system strength, the easier it is to manage the power quality to the relevant standards. As penetration of renewable generation increases, the system strength continues to decline and the power quality becomes more likely to deteriorate. We need to better understand the future trends of power quality to manage a low-carbon system.

Whilst we have identified regional requirements for SCL and dynamic voltage, we have generally considered inertia to be a system wide requirement. As we operate at lower inertia levels we may need to better understand if there are regional variations in our inertia requirement.

There is currently an NIA project in flight, exploring and testing automated and probabilistic approaches for modelling angular stability. This will enable year-round boundary capability calculation for stability accounting for a number of sources of variability and uncertainty and enabling ESO to consider the possible issues across the system.

The focus of our stability requirements to date has been looking at the impact on the operation of the transmission network. There are likely to also be issues on the distribution network which Distribution System Operators (DSO) may highlight in the future. We will need to better understand the coordination of planning, technical assessment and interaction of services as challenges are identified on the distribution network.

As the concentration of generation connected to the system via power electronics based converters increases, the risk of control system interactions is likely to become more prevalent. Getting a better understanding of this risk requires detailed electro-magnetic transient (EMT) studies to be carried out which in turn requires more detailed modelling of the network as well as the converters. There are several innovation projects under way such as TOTEM (Transmission Owner Tools for EMT Modelling) which is developing a full GB network model in the EMT environment and DETECTs (Developing Enhanced Techniques to Evaluate Converter-dominated Transmission System Operability), which is exploring the best practices for conducting such EMT studies using a specific study case in an area where converter-based generation is already prominent.



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Voltage

Voltage

Summary

Maintaining voltage levels across the transmission network has become increasingly challenging as the reactive power requirement increases and available capacity to meet the requirement from synchronous machines decreases.

Voltage levels are managed through the injection and absorption of reactive power. Decreasing reactive power demand on distribution networks and reducing power flows across the network are driving an increasing need to absorb reactive power on the transmission system. The closure of coal and gas fired power stations is reducing the available reactive power capacity. In addition the reduced running hours of these power stations means that we have to synchronise them out of merit to access their reactive power capacity. This increases balancing costs.

Our latest Voltage Screening Report (June 2021) has highlighted numerous areas where there is reducing reactive capacity or a reactive need to reduce balancing costs. Across seven regions we will lose access to 3,600MVAr by 2025 and an additional 1,000MVAr by 2030 through plant closures. Whilst fossil fuel power stations in those areas are available today, there is a need to ensure from a compliance, cost and carbon perspective that alternative sources can be procured. Further work is planned which will identify the reactive power requirements out to 2030.

Our voltage pathfinders are identifying new providers of reactive power services, helping us meet some of our locational operational needs out to 2034, and contributing to our 2025 zero carbon ambition.

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Voltage

What do we mean by voltage?

Our transmission licence requires us to plan and operate transmission system voltage levels to set criteria. Here we focus on the need to manage steady state voltage and voltage step change. Voltage stability is a different system need and is covered in the Stability chapter.

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

To maintain a secure and operable system, the need for reactive power support continues to grow as the energy system decarbonises, leading to increasing reactive power requirements and decreasing sources of reactive power. Reactive power requirements are locational, meaning reactive power providers need to be electrically/geographically close to where the need exists.

Drivers behind this increase in reactive power requirements include a reduction in reactive power demand, lightly loaded lines (resulting from lower active power demands) which lead to an injection of reactive power, and increasing numbers of underground cables which also inherently inject reactive power. Meeting these reactive power requirements is becoming more difficult and costly as reactive power providers close (e.g. coal and gas generators) and other existing reactive power providers are displaced from the energy market by embedded generation and lower active power demands. This requires us to synchronise additional units at extra cost. New generation with reactive power capability or obligations are increasingly locating in the south west of England, off the east coast and in Scotland, and are ineffective at meeting the reactive power requirements which are typically near demand centres (e.g. London and West Midlands).

The transmission system sees various loading patterns and system characteristics at different times during the day and throughout the year. Operationally, this is particularly challenging during yearly extremes e.g. minimum demand during overnight or sometimes in the middle of the day in summer as a result of the high penetration of solar generation. While there has always been a requirement for sources of reactive power to make sure that voltage remains within compliant limits at low demands, there is often not enough headroom to synchronise generators to access their reactive power.

In future years as we see growth in electric vehicles, heat pumps and more embedded generation, we could see the need to manage a reactive power shift from typical overnight periods to during the day.

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Voltage

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

Across NGESO and the GB transmission owners, there are licence obligations which require the need to design, plan and operate a compliant network. Together with industry we need to collectively manage this increase in reactive power need and decrease in reactive support. We want to do this by:

- Finding new ways of managing the production and absorption of reactive power,
- Ensure the effective usage of the existing network assets,
- Further develop how we define, communicate and contract our requirements, and
- Find new providers of reactive power.

Future stability service providers will deliver some dynamic voltage capability, and this will help to reduce our need for static voltage capability. Stability providers will not necessarily meet all our requirements due to the locational nature of reactive power requirements, and dynamic voltage capability is typically more expensive than static provision so we must ensure we economically meet our requirements.

The voltage pathfinders have begun to explore new ways of procuring reactive power services via long-term contracts and have been ambitious in competing TO assets with commercial solutions. The pathfinders have encountered significant blockers for Distributed Energy Resources (DER) to provide material reactive power services at the transmission level. This is mostly because network reinforcement is required at the distribution level to enable DER to operate outside of the power factors in their connection agreements. In contrast, the Power Potential project has had some success with accessing reactive power services from DER. Power Potential did encounter technical blockers, but for a few parties the operational parameters were able to be accommodated in the distribution network to enable dynamic reactive power operation. More detail is available in the final report for the innovation project. We will combine the learnings from this with our work with distribution network owners on how to manage reactive power across the transmission-distribution interface through a whole system approach. Combined, these will reduce reactive power requirements and increase access to sources of reactive power.

The pathfinders have focussed on long-term requirements and is attractive for new build assets, but there is likely to be residual requirements in shorter timescales. The Future of Reactive Power programme is investigating whether a short-term market could be used to access reactive power from existing assets which may or may not be providers of the obligatory reactive power service.

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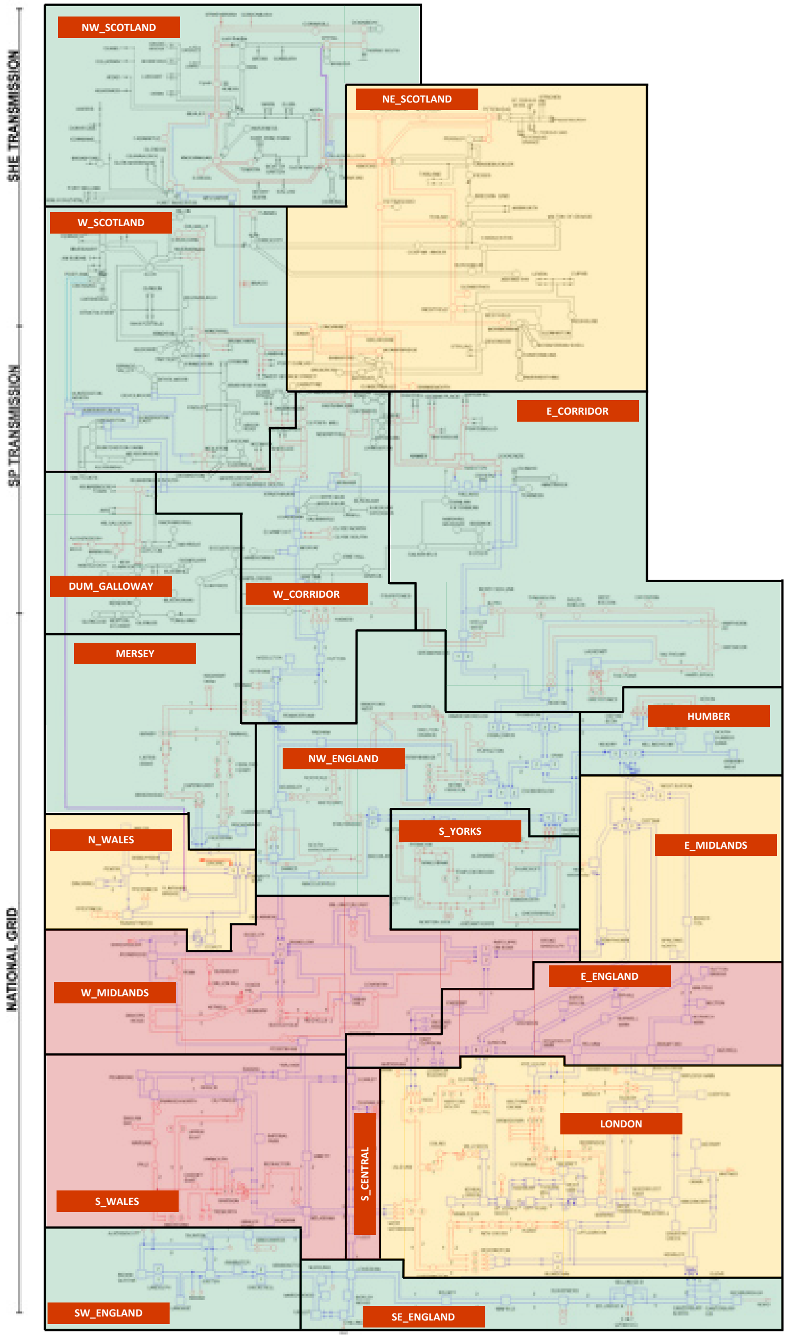
Voltage

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

To meet our 2025 zero carbon ambition we need to stop relying on traditional sources of reactive power (coal and gas generation). In 2019 we published a map which showed which voltage regions could manage voltage using zero carbon solutions. This has been updated to reflect the impact of the voltage pathfinders. MERSEY has been turned green as it will have zero carbon solutions from April 2022. Whilst the Pennine pathfinder is still ongoing, only zero carbon solutions have been submitted. Therefore, we can assume that the outcome will be zero carbon solutions, which means we can turn E_CORRIDOR and NW_ENGLAND green.

HUMBER and E_MIDLANDS have changed following our recent voltage studies for 2025 which are covered further on.

As the network diagram shows, there is a swathe of regions across England which are highly reliant on fossil fuel generation to manage voltage levels. The Voltage Screening Report highlights some of the contributing factors, including low electricity demand, power flows and long transmission lines.



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

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Voltage

Whilst the pathfinders have delivered zero carbon solutions, there is still more to be done to meet our 2025 zero carbon ambition. This ambition is made more difficult as we anticipate that by 2025 we will lose access to ~3.6GVAr reactive absorption capacity through plant closures, with a further 1 GVAr by 2030. We do not foresee requirements reducing either if the trend in the graph continues.

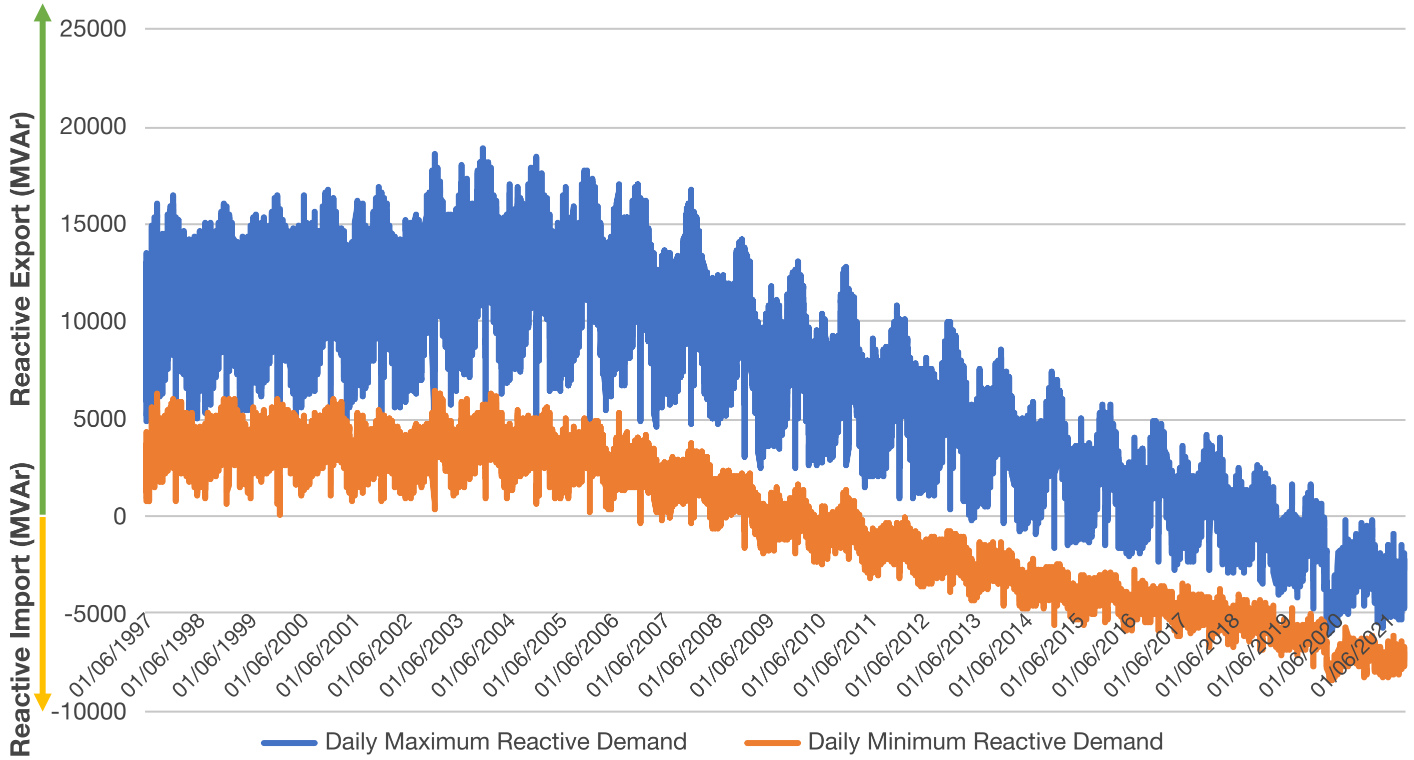
The graph shows the transfer of reactive power between transmission and distribution networks. It shows that reactive demand at the interface between transmission and distribution has swung to reactive generation, leading to the need to absorb reactive power on the transmission network.

Generally our requirement for voltage support is higher as the demand drops. Over a normal daily load curve, this means that our need is generally greatest overnight because this is when both real and reactive power demand is low. However in the short to medium term, we are experiencing an increasing need for voltage support in certain areas.

Our 2021 GB Voltage Screening Report has explored the following voltage challenges across the whole network:

- a dependency or over-reliance on certain assets or generation or
- historically costly real time voltage actions and locations that were compliant with pre-fault planning voltage limits from historic data or
- faults on the network which could have resulted in voltage in excess of allowed planning limits.

Daily maximum and minimum reactive transfer between transmission and distribution networks



The report identified seven regions with potential voltage issues: West Midlands, London, South Central, South West Peninsula, Pennines, North Wales and South Wales. It also highlights areas of the network which will have a need for new reactive capability – to either ensure we have enough capability to maintain compliance, to help deliver our 2025 zero carbon ambition or to reduce balancing costs. This report is a high-level analysis and indicates the areas of need but does not provide granular reactive requirements.

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Voltage

2025 Voltage Studies

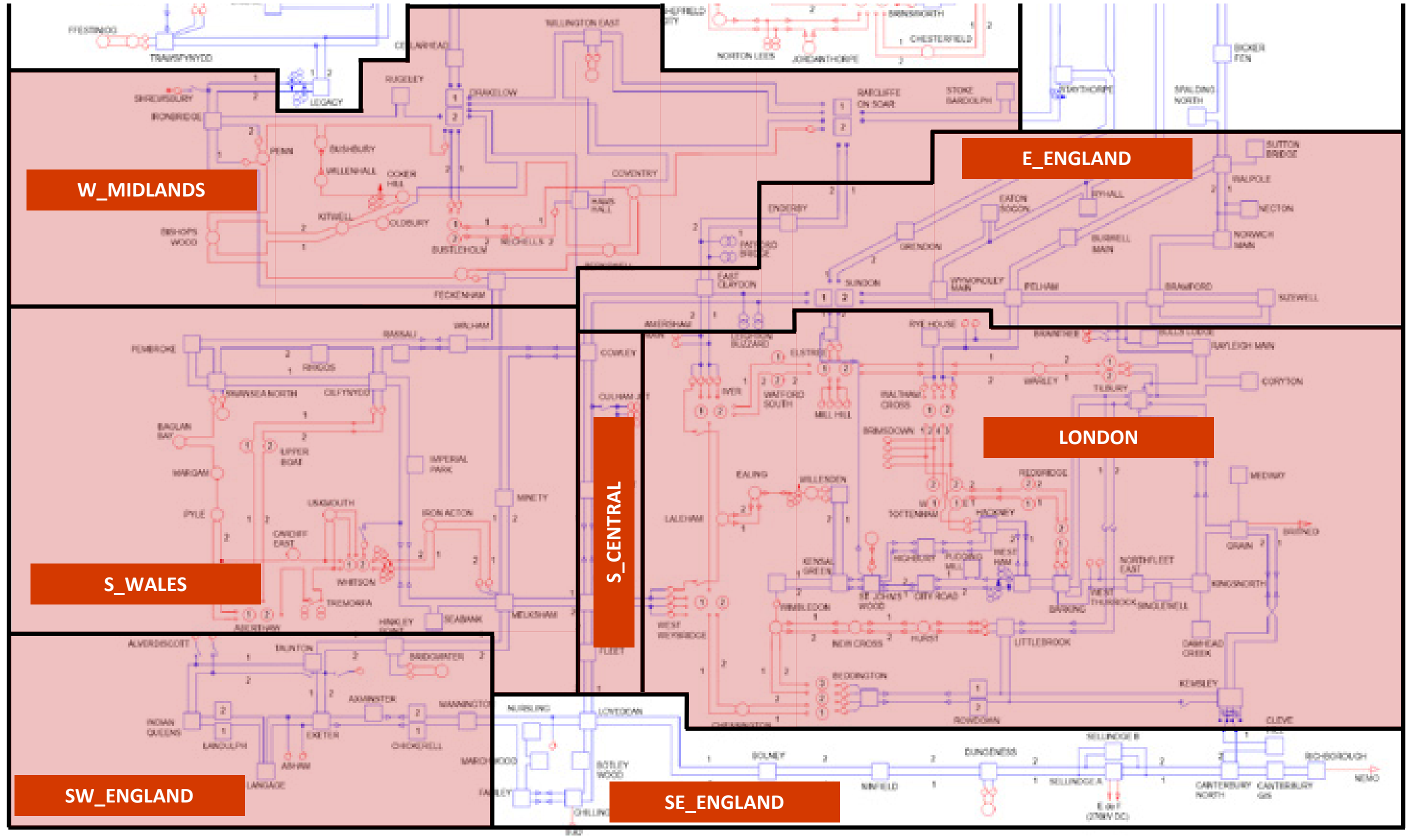
We have modelled our reactive power requirements to manage high voltages across England and Wales in 2025. These studies modelled the required volume of reactive power absorption to meet the planning obligations for steady state voltage and voltage step change, set out in the Security and Quality of Supply Standards (SQSS). The regions which experience high voltage levels, and the modelled volumes of required reactive power absorption are in the table below.

The high voltage issues are seen from the Midlands to south of England, shown in the network diagram. It is important to note that the study results in this report are to indicate the regions which experience the high voltages and the required reactive power volume to solve. It does not necessarily indicate the regions where suitable and effective solutions should or could be located.

Reactive power residual absorption requirements by region(s)

Region	MVAr need (residual requirement)
LONDON	300MVAr
W_MIDLANDS	300MVAr
S_WALES and S_CENTRAL	600MVAr
SW_ENGLAND	200MVAr
E_ENGLAND	200MVAr

Map of voltage regions which experience high voltages outside of SQSS limits in our modelled scenario for 2025



Rollover for more information

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Voltage

How do the requirements change under differing Future Energy Scenarios?

Across the scenarios, the levels and location of generation and demand differ, which affect the reactive power requirements across the network. The 2025 studies have used Leading the Way as the base case and mainly looked at low and mid wind scenarios.

The low wind scenario is set at 15% load factor as this removes access to the obligated reactive power capability on these units. The low load factor on wind units leads the model to self-dispatch some fossil fuel generation to meet the minimum demand. Once reactive power contribution is considered from these units there is a residual requirement of up to 1600MVAr.

If we are to achieve our zero carbon ambition in 2025, industry will need to provide zero carbon solutions to meet this residual requirement, and we will need to ensure blockers are removed to enable them to participate in future procurement events.

When we increase the wind load factors to a level which replaces the self-dispatching fossil fuelled generation, the residual reactive power requirement from the low wind scenario is sufficient to meet our needs in this scenario. Assuming the residual requirement is met by zero carbon assets, we would meet our zero carbon ambition in this scenario also.

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Voltage

What is the next big operational challenge?

The interaction between network owners and specifically on the transmission/distribution interface is significant. Accessing reactive power from DER and managing the transfer of reactive power between distribution and transmission networks are both key enablers for us to maintain system voltages and achieve zero carbon operation in 2025.

We have investigated the potential for managing reactive power transfer by applying transfer limits at the interface point. However, this approach is impractical due to numerous factors. We are now looking into a whole system approach with distribution network operators (DNOs) so that voltage issues can be identified in longer term planning timescales. This would enable a comprehensive cost benefit analysis of all options and provide sufficient lead time for new assets.

There is also a need to work with DNOs to improve reactive power forecasting which would enable more accurate modelling, leading to improved analysis and identification of any voltage issues.

These should mean we can find solutions to the increasing volume of reactive power transfer between distribution and transmission networks.

Accessing reactive power from DER has been explored by the voltage pathfinders and the Power Potential project. Each has met its own set of challenges but both have demonstrated that DER can help solve transmission voltage problems. The Future of Reactive Power project is working with DNOs to better understand the limitations of DER providing reactive power services.

These will give us access to more reactive power providers in a greater variety of locations.

On top of these, the distribution system operator transition is driving profound change. Together the next big operational challenge in managing reactive power will be to ensure all of these changes come together to create an operable, secure system from a voltage perspective and at the lowest cost to end consumers.

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Thermal

Thermal

Summary

Our thermal requirements are forecast to grow out to 2030 and beyond. In some areas of the network we will see peak power flows which are 400% greater than current boundary capability. We cannot manage these boundaries by redispatching generation alone – Article 13 of the Recast Energy Regulation, as retained in UK law, requires us to limit the redispatch of renewable and high-efficiency cogeneration to 5%. The NOA analysis shows that we are likely to exceed this threshold before 2025. Elements of the constraint five point plan are looking to mitigate the volume of redispatch ahead of 2025.

Between 2025 and 2030, the Network Options Assessment (NOA) forecasts that generation from renewables will exceed 50% of total demand, meaning the 5% threshold will no longer apply. The constraint five point plan seeks to mitigate rising constraint costs ahead of new build recommendations.

Beyond 2030, the NOA recommends optimal network reinforcements which increase capacity to facilitate the growth in generation. Where residual requirements remain, or timescales prevent network reinforcement, commercial solutions are a potential option.

Going forward, increasing growth of flexible resource will drive greater use of markets to manage transmission constraints instead of large reinforcements. This approach is currently being developed and tested through our Regional Development Programmes (RDPs) with a view to rolling out this functionality more widely in the longer term.

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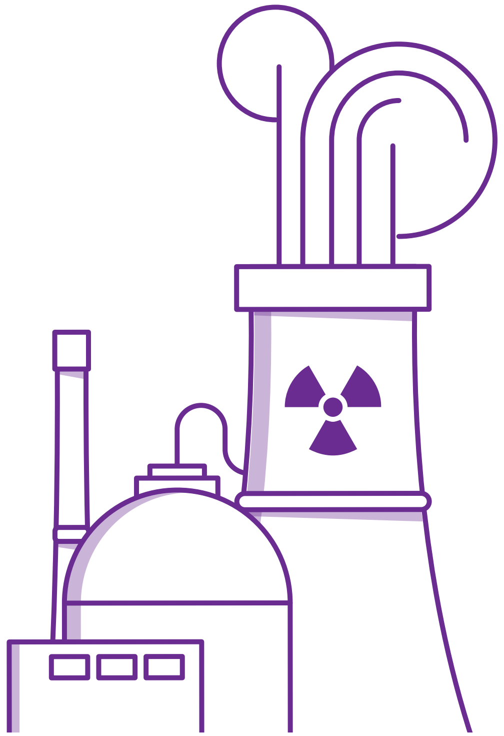
Thermal

What do we mean by thermal?

The thermal workstream covers the ability of the transmission network to transport power from A to B.



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

In order to get to net zero by 2050, we must increase the amount of generation connected to the electricity network. This is needed to meet increased demand due to electrification (of transport, heat, and industrial processes) and because renewable generation has a lower load factor than conventional generation sources. This new generation is located remote from demand centres and, where economic to do so, requires additional network infrastructure to connect it to demand. We forecast that the cost of the additional infrastructure to be up to £16bn over the next 20 years.

Until this new infrastructure is built, we will incur constraint costs. These come from there being less capacity on the network than the generation dispatch needs. In such cases, when generation output exceeds network capacity, we often need to pay generators to constrain (reduce) their output. These costs have two components – the cost of turning down a generator "behind the constraint" to relieve the constraint, and the cost of turning up another non-constrained generator to satisfy the energy imbalance.

Paying these constraint costs is critical to the development of renewable generation capacity in the short-term. It means that new renewable generation is online sooner, and at times before the new network capacity is in place. The operational costs they generate are more than offset by optimising transmission investment and the long-term power price savings they enable.

It should be recognised that the thermal constraints are generally a cost issue, rather than security related. The balancing mechanism ensures that the operational actions needed are available, but at a cost. This challenge is set out in our Modelled constraint costs publication.

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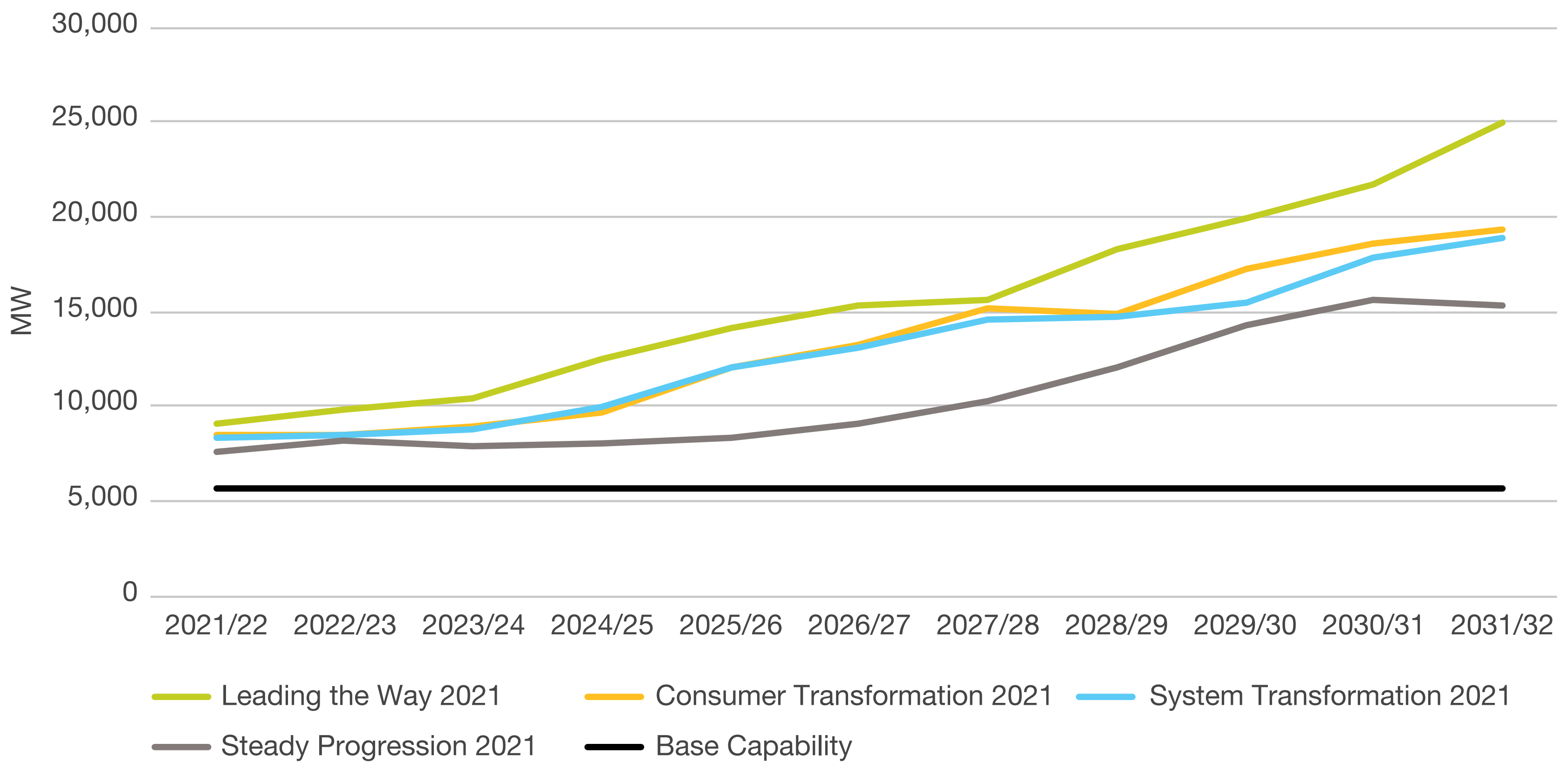
What capability do we need to meet these changing operability challenges?

The Electricity Ten Year Statement (ETYS) sets out the future requirements of the electricity transmission system, highlighting areas with uncertain future power flows and requirements which provide opportunities for system development and innovation. It shows an increased requirement in bulk power from the tip of Scotland, B0, through Central Scotland, B4, across the Anglo-Scottish border, B6 and through the Midlands, B8 & B9, as substantial new renewable generation connects in the north of the country further adding to the existing north to south flow. By 2030 the B6 boundary could be seeing a need to transfer 21.5GW compared to a current capability of 6GW.

Winter Peak required transfer for B6



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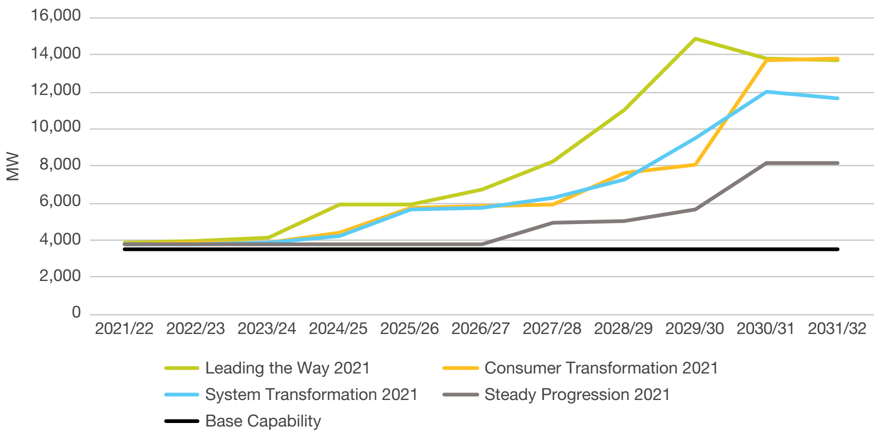
Another area that sees a significant growth in renewable generation as well as interconnection is the south east of England. Increased offshore wind connecting on the east coast increases power flow through East Anglia, EC5 (13.7GW transfer against a 3.5GW capacity), and further south towards London, LE1 (18.4GW transfer against an 9.3GW capacity), and the south coast, SC1, 2 and 3 where there are a growing number of interconnectors to Europe.

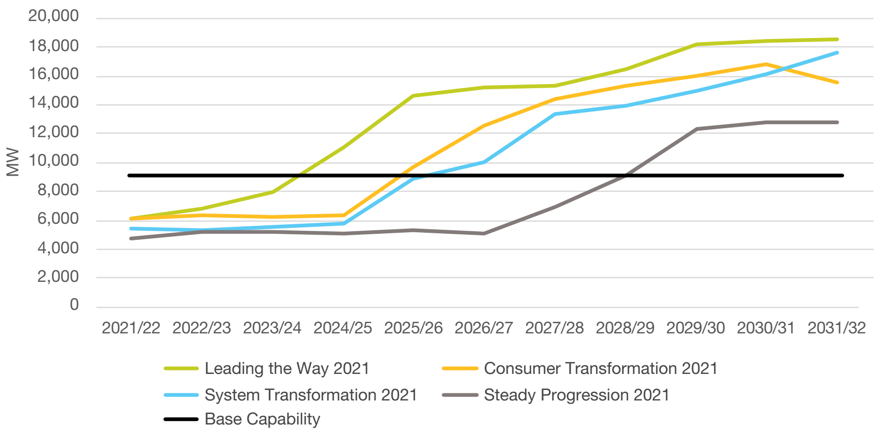
As the electricity system transitions to a lower carbon and more distributed model, there is a shift from energy predominately being supplied by transmission connected generation to a world that includes large volumes of distribution connected generation, flexible demand and storage. This requires a ‘whole system’ approach to the commercial and technical operation of transmission and distribution networks. National Grid ESO and distributed network operators (DNOs) across Great Britain are working together through Regional Development Programmes. The aim of these programmes is to maximise the opportunities for more efficient deployment of distributed resources, and reduce overall system costs for energy consumers.

Our current RDPs have been developed predominantly from challenges identified through the connections process; examining areas where large amounts of distributed energy resources (DER) are looking to connect and identifying ways to enable those connections more economically and quickly, while ensuring network operability. In future, we are looking to determine a more proactive and process driven approach to identifying areas where whole system approaches would be beneficial. In addition, the current RDPs are looking at addressing thermal transmission constraints but there may be need cases to address other system needs, such as voltage, from a whole system perspective.

Winter Peak required transfer for EC5



Winter Peak required transfer for LE1



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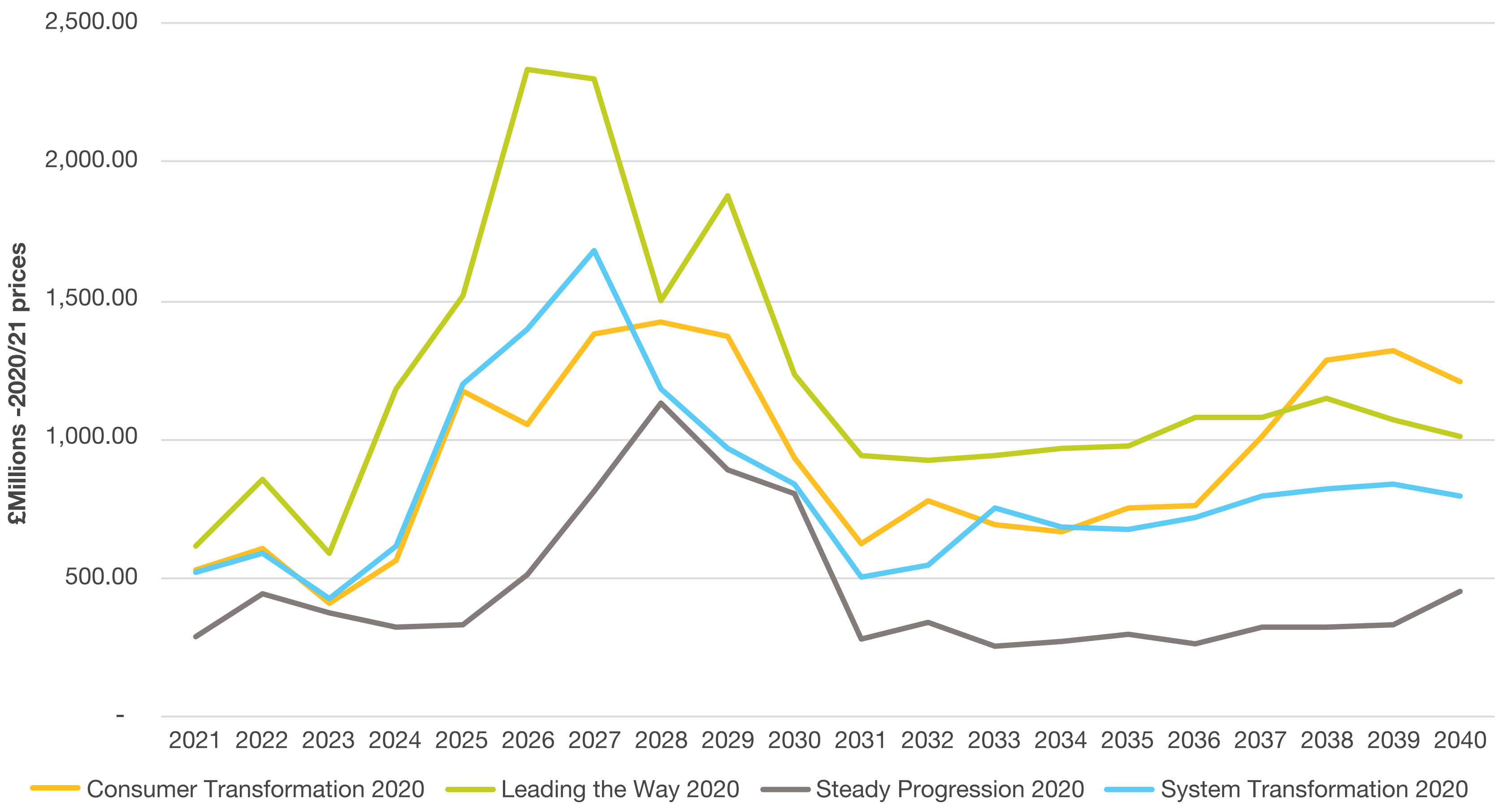
What are the requirements for 2025 (zero carbon ambition) and beyond to 2030?

The NOA 20/21 identified a need for at least 113 reinforcements on the transmission system over the next 20 years. A number of those are smaller, incremental reinforcements maximising the use of existing assets helping to reduce constraint costs in the short term. Beyond this new infrastructure is required to reduce constraint costs in the long term, such reinforcements include both new onshore transmission circuits as well as subsea HVDC cables.

New large asset based NOA solutions cannot be delivered in time to meet requirements for 2025 and in the interim, constraint costs are forecast to rise from today's levels. The ESO is looking to further reduce these constraint costs through the five point plan and, where possible, commercial solutions in the NOA which can be delivered through the constraint management pathfinder.

Modelled Constraint Cost after NOA6 Optimal reinforcements



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How do the requirements change under differing Future Energy Scenarios?

The four Future Energy Scenarios (FES) provide a wide range of credible future outcomes; however, one thing is clear, the energy transition is driving a greater requirement for power flow from north to south and from the coastline to inland. Both of these drivers require investment in the transmission system to adapt to the future energy landscape, the only difference is the scale and pace of this change.

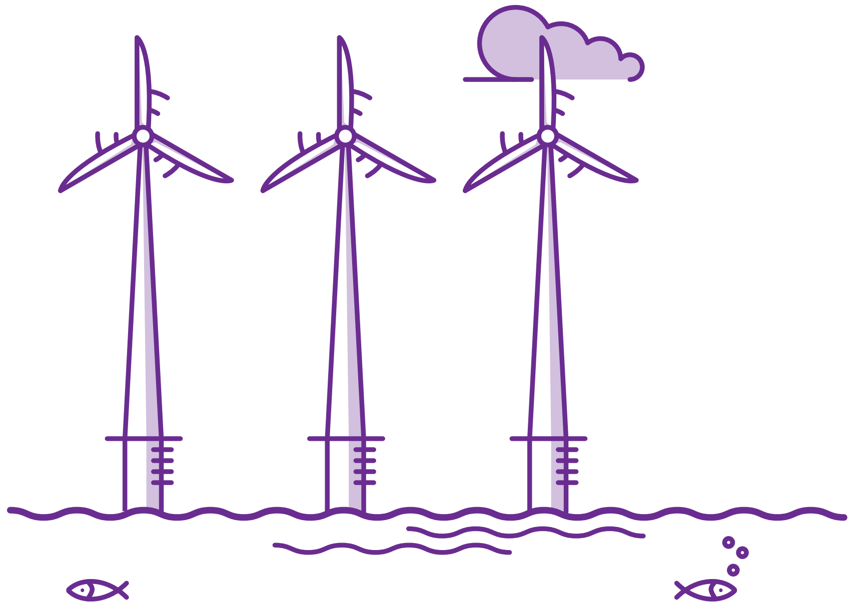
What is the next big operational challenge?

In the long term future, FES indicates that we will probably need 30+GW of capacity out of Scotland. Current capacity out of Scotland is ~6GW. This is a massive increase and will be a considerable challenge.

The medium term is about the constraint challenge by 2027 due to the significant constraint challenges until the new network infrastructure is built. The constraint five point plan is investigating ways to mitigate the significant rise in balancing costs.

Offshore co-ordination – The ongoing Offshore Transmission Network Review (OTNR) is likely to significantly change the way offshore customers and interconnectors are connected. The desire is to connect offshore parties in a more coordinated manner, rather than the radial, one by one approach currently taken. This coordination could provide constraint cost saving benefits by effectively increasing network capacity for north to south power flows.

The OTNR is split into three workstreams looking at different changes over different timescales. Early Opportunities and Pathway to 2030 are the two earliest workstreams, and both are investigating new ideas and models for how to connect offshore parties to the network. The implementation of any of these new ideas and models could have operability implications that will need to be investigated.



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Restoration

Restoration

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

Meanwhile changes on the system such as the reduction in synchronous generation and increase in embedded generation 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.

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Restoration

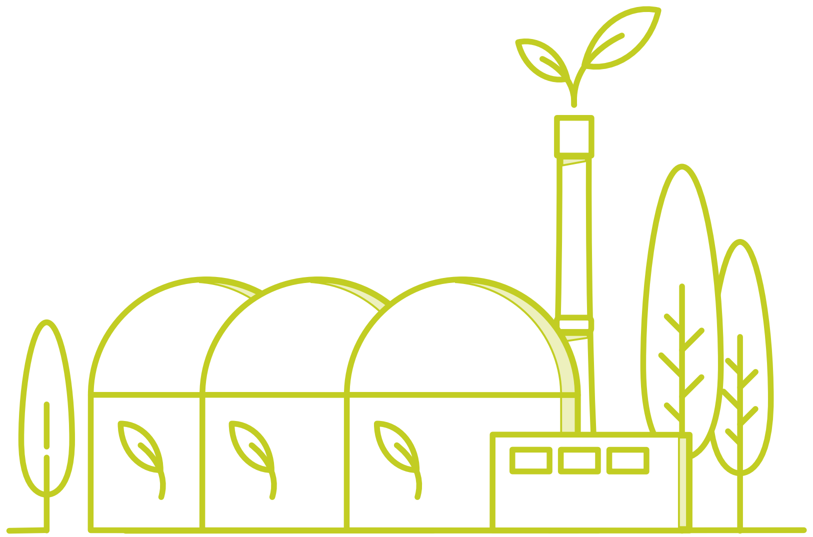
What are our obligations and what are the future operability challenges?

The Grid Code details an essential requirement for the National Electricity Transmission System (NETS) to incorporate Restoration Capability, however, there has previously been no defined standard to enable the ESO to prescribe any further detail of this capability requirement.

In the past system restoration has been highly dependent on large transmission connected fossil fuel generators. This approach relies on ensuring that a minimum service level is retained across different regions by maintaining the availability of stations which can require them to run more often than is economic for them to do so in the market. As the electricity system becomes more diverse, with fewer fossil fuel generators and more generation connected via the distribution network, we need to understand how a range of different users can support the restoration of the system.

In April 2021, BEIS announced their intention to strengthen the existing regulatory framework by introducing a new Electricity System Restoration Standard (ESRS). Following Ofgem's consultation and amendments to the ESO licence, we are obligated to restore 100% of GB electricity demand within five days. The ESRS also specifies that demand should be restored regionally, with 60% of regional demand restored within 24 hours.

As a result, we will need to work with industry to ensure we can meet the requirements of the ESRS by the 31 December 2026 deadline. Importantly, the obligation for regional restoration means we will need to understand the regional specifications for both inertia and SCL to enable this.



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Restoration

Meeting the requirements of the Electricity System Restoration Standard (ESRS)

The creation of industry work groups with a steering committee will need to be developed to deliver the ESRS. A range of areas have been identified where we will need to work with industry to develop our approach to deliver the new standard:

- **Future networks –** to look at the development needs on networks to accommodate the changes in the generation mix across GB and the implementation of the ESRS.
- **Modelling and restoration tools –** to develop a framework that will give relevant industry parties confidence that the restoration model outputs are an accurate representation of restoration times in GB.
- **Assurance activities –** in coordination with other industry working groups as well as relevant regulations, define which assurance activities should be progressed across the industry for restoration.
- **Markets and funding mechanisms –** to understand how to further remove market barriers and assist the development of agile solutions for restoration.
- **Regulatory framework –** to deliver the changes needed in the relevant industry codes that will enable the implementation of a fit-for-purpose framework for the ESRS.
- **Technology and locational diversity –** to assess how different technologies can contribute to faster restoration times and an enduring supply of demand (2 to 5 days after a power outage event).
- **Communications infrastructure –** to develop an understanding of the role communications in restoration and enable the delivery of a secure and resilient communications infrastructure.
- **Diversification of capability –** Generation is becoming less controllable due to both to intermittent power sources such as wind and the increase in generation connected via the distribution network. We need to understand how to include intermittent generation in our restoration process. We also need to consider how to utilise smarter and flexible grids, bottom up vs. top down restoration and local power islands. The use of shared tools and communications across ESO, DSO, TOs and users will also be vital to future restoration capability.

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Restoration

Competitive procurement

Historically, restoration services were procured bilaterally from large fossil fuel generators, however, our ambition is that by the mid-2020s we will be running fully competitive procurement of restoration services wherever advantageous. This will include submissions from a range of technologies, connected at different voltage levels.

With the changing generation profile, there are an increasing number, and type of providers who can assist with restoration during a power outage. To maintain a flexible, fit for purpose restoration plan, we have sought to enable varied technology restoration solutions. This reduces the reliance on any individual solution for restoration and will increase competition.

Development work is happening through competitive procurement process being trialled in different regions based on our service requirements:

- A full tender will be launched in April 2022 for the South-East region for five-year contracts commencing from October 2025. Expressions of interest will close in June 2022. This competitive procurement event will also, to extent it is possible, include providers delivering Distributed Re-Start services.
- We also plan to begin a begin a competitive process in Oct 2022 in Northern zones (Scotland, NE, NW), focussing on services from Distributed Restart, (plus wind and interconnectors if appropriate to do so) for services starting April 2026.

Learning from these processes will enable us to shape and determine the procurement approach for future competitive events. As technology readiness levels increase, we will adapt our processes to enable wider participation, which will increase competition and drive down the overall cost of this service to the consumer.

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

By 2025, we expect that most coal power stations will have closed. Coal stations were previously a traditional source of restoration services and so we have been procuring new services to replace these with services from other types of provider. We will need to continue this process of replacement over the coming years.

Gas fired power stations will continue to be part of the portfolio of stations providing restoration services, however these stations are expected to run less often in the future and to meet our zero carbon ambition we need to be able to minimise the amount of warming required.

The pace at which the current fleet of power stations close impacts how quickly we need to find alternative services. The requirements of the ESRS to restore the system as a percentage of demand means that the pace of growth of demand will also impact on the complexity of this challenge.

The Distributed Restart innovation project is due to complete in June 2022. The project explores how distributed energy resources such as solar, wind and hydro can be used to restore power to the transmission network during a National Power Outage. This project will enable us to better understand how we may be able to restore the network from the distribution up to transmission level rather than having to rely on transmission connected generation to restart the network. A better understanding of this approach will change the nature of our requirement as if successful can broaden the range of sources which can support during a system restoration.

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