# Electricity Ten Year Statement

November 2019

nationalgridESO

# How to use this interactive document

To help you find the information you need quickly and easily we have published the *Electricity Ten Year Statement* as an interactive document.

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This will take you to the contents page. You can click on the titles to navigate to a chapter.

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# Foreword

## Welcome to our *Electricity Ten Year Statement (ETYS)*. This statement is our current assessment of the future requirements of GB's electricity transmission system. It highlights areas with uncertain future power flows and requirements which provide opportunities for system development and innovation.

**Our *Electricity Ten Year Statement (ETYS)*, along with our other System Operator (SO) publications, aims to encourage innovation and inform developments that ensure a secure, sustainable and affordable energy future. The *ETYS* is a key input into our *Network Options Assessment (NOA)* process that makes recommendations for future investments and solutions. The *ETYS* and the *NOA* primarily focus on the bulk power transfer across major transmission boundaries in GB, however there are many other system requirements that are important for secure and efficient system operation.**

We are in the midst of an energy revolution. The economic landscape, developments in technology, and consumer behaviour are changing at an unprecedented rate, creating more challenges and opportunities than ever for our industry. Our 2019 *Future Energy Scenarios (FES)*, developed with stakeholder and industry input, aims to inform decisions that will help us achieve carbon reduction targets and shape the energy system of the future. These scenarios are at the heart of the *ETYS* process in determining future transmission network needs.

The themes in this year's *FES* are continued closure of fossil-fuelled generation, growing renewable and distributed generation, increasing electric vehicle and heat pump demand, and greater use of interconnectors. These changes are leading to high north-to-south transmission flows across Scotland and much of the North of England to meet demand in the Midlands and the south. The number of interconnectors that are predicted to connect towards the South East of England also create potential overloads on the network and a key focus is to ensure that we can meet these needs.

As a result of the future transmission needs we have identified in this document, the Transmission Owners (TO) alongside the Electricity System Operator (ESO) have provided development options for the *Network Options Assessment (NOA)* process. These options range from large asset builds through to smart grid management systems and new commercial products. The *NOA* aims to make sure that the transmission system is continuously developed in a timely, economic and efficient way, providing value for our customers. Using the results from *ETYS 2018*, the *NOA 2018/2019* recommended £59.8 million of development spend on network reinforcements in 2019.

As you may be aware, on 1 April 2019, the ESO became a legally separate entity within the National Grid Group. Separating the ESO business provides transparency in our decision-making and gives confidence that everything we do will promote competition for the benefit of consumers. We continue to facilitate the transition to a sustainable energy system by working with our stakeholders to make our electricity networks fit for the future and to deliver reliable, affordable energy for all consumers.

In line with our commitments in the ESO Forward Plan and the Network Development Roadmap, we are using our pathfinding projects to assess a broader range of network issues and encourage options from a range of industry participants. In a new dedicated chapter this year, we present additional studies that demonstrate how we are taking steps towards enhanced tools and analysis to improve our network planning. You can find further details about our enhanced role in network planning in the ESO Forward Plan. You can also find further details about the changes we are making to our methods in the Network Development Roadmap. Thank you for your continued feedback on the

*ETYS* process. It is vital that we share the right data in the right way to make this a useful document and a catalyst for wider debate.

Please share your views with us; you can find details of how to contact us on our website **https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys/**.

**Craig Dyke**
Head of Networks, ESO

# Key messages

## We have assessed the capability of the National Electricity Transmission System (NETS) against the requirements derived from the *Future Energy Scenarios (FES)*, using boundary analysis techniques.

**Below is a summary of the main findings, together with how these findings will be used in the *NOA* and the future development of the *ETYS*.**

1. Over the next decade, the NETS will face growing needs in a number of regions due to:
   - Increasing quantities of wind generation connected across the Scottish networks, doubling north-to-south transfer requirements. For example, the flow through the Scotland–England boundary is expected to reach 15.9 GW in *FES'* **Two Degrees** scenario by 2029, almost three times the current 5.7 GW boundary capability with the Western HVDC reinforcement operational.
   - A potential growth of more than 6 GW in low-carbon generation and interconnectors in the North of England, combined with increasing Scottish generation, which could increase transfer requirements and the need for reinforcements in the Midlands.
   - Potentially high growth of up to 8 GW in generation coming from offshore wind on the east coast connecting to East Anglia, which could increase the need for reinforcement in this region of the network.
   - New interconnectors with Europe, which will place increased requirements on the transmission network, especially the southern and eastern regions where it is anticipated that there could be significant concentration of interconnectors. If interconnectors export to Europe at the same time as significant wind output, there will be high power flows across the whole transmission network from north to south.

2. The *NOA* process will evaluate options for NETS development and condense them to a set of preferred options and investment recommendations. These will be published in the *NOA 2019/20* report in January 2020.
   - For *NOA 2019/20*, we expect to assess around 180 options and, at the time of writing, seven have been initiated by the ESO. Following our cost-benefit analysis (CBA), we will recommend options requiring expenditure in 2020 as well as those that could be delayed.

3. The NETS will see growing impact from intermittent energy sources, such as wind and solar, combined with new technologies such as electric vehicles, energy storage and heat pumps. As a result, the requirements of the NETS are becoming increasingly complex and more frequently being driven by conditions other than winter peak demand. We are developing analysis tools and processes to assess these changing requirements. In a dedicated chapter this year, we publish further results of our thermal year-round assessments.

4. Through our Network Development Roadmap, we are shaping the future development of the *ETYS* and *NOA* publications as we work to facilitate competition, and improve our reinforcement recommendations for the benefit of our customers and consumers. We will shortly be publishing an update on progress of the roadmap together with our next steps.

# Chapter 1
## Introduction

**The *Electricity Ten Year Statement (ETYS)* presents the National Grid Electricity System Operator's (ESO) view of future transmission requirements and the capability of Great Britain's (GB) National Electricity Transmission System (NETS). This is a significant part of our annual network planning process. Through it, we identify potential requirements for network development, which are assessed through the *Network Options Assessment (NOA)*[1] process.**

This is the eighth *ETYS*, the first we publish as the ESO. We produce *ETYS* with help from the Transmission Owners (TOs) in Scotland (SHE Transmission and SP Transmission) and in England and Wales (National Grid Electricity Transmission).

We aim to build on the *Future Energy Scenarios (FES)*[2] and provide an overview of the NETS, its power transfer capability and its potential future requirements.

Since our first *ETYS* in 2012, and the Seven Year Statement that preceded it, our publications have evolved and some of the information previously included in *ETYS* is now published in separate, more focused documents, described below.

We welcome your feedback, which helps us to improve our publications. We want to know how you use *ETYS* and how we can make it more useful. Our contact details are included at the end of this document.

[1] https://www.nationalgrideso.com/insights/network-options-assessment-noa

[2] http://fes.nationalgrid.com/

# 1.1 *ETYS* and the ESO publications

Part of our role is to assess and make recommendations about reinforcing the NETS to meet our customers' requirements economically and efficiently. We do this in three stages. The first establishes the *Future Energy Scenarios (FES)*, described in the next chapter. The second determines the NETS's current capability and future requirements, described in *ETYS*. And finally, we evaluate network development options, and publish investment recommendations in the *NOA* report.

The *ETYS* complements the *NOA* report, because information about NETS capability and future requirements feed into the analysis used to produce the *NOA* report. By updating the future requirements based on the updated scenarios, the *NOA* recommendation can also change. Based on last year's *ETYS*, the *NOA 2018/19* recommended investing £59.8m this year to potentially deliver 25 projects worth almost £5.4bn.

The *System Operability Framework*[3] *(SOF)* takes a holistic view of the changing energy landscape to assess the future operation of Britain's electricity networks. It combines the change in generation and demand from the annually updated *FES* with network capability from *ETYS* to assess future system requirements. *SOF* and *ETYS* complement each other to ensure the future NETS is both operable and can transmit power from suppliers to consumers. In 2017, we moved from a single annual *SOF* publication to reports on a range of topics. Figure 1.1 shows the connection between *ETYS* and the relevant ESO documents.

**Figure 1.1**
*ETYS* and ESO documents

**System Operability Framework**
How the changing energy landscape will impact the operability of the electricity system.

**Future Energy Scenarios**
**July**
A range of credible pathways for the future of energy from today to 2050. Scenarios are unconstrained by network issues.

**Electricity Ten Year Statement**
**November**
The likely future transmission requirements on the electricity system.

**Network Options Assessment**
**January**
The options available to meet reinforcement requirements on the electricity system.

[3] https://www.nationalgrideso.com/insights/system-operability-framework-sof

# 1.2 *ETYS, NOA* and *TYNDP*

The *ETYS* and *NOA* consider cross-border electricity transmission networks (including interconnections with mainland Europe). European transmission developments are described in the *Ten Year Network Development Plan (TYNDP)* which is produced by the European Network of Transmission System Operators for Electricity (ENTSO-E). It is similar to the *ETYS* and *NOA* but covers all European Transmission System Operators (TSOs). It is published every two years with TSOs' input in accordance with Regulation (EC) 714/2009. The next publication is due in Q4 2020.

Although *TYNDP*, *ETYS* and *NOA* all highlight future network developments, there are important differences:

- *TYNDP* is produced every two years, whereas the *ETYS* and *NOA* are produced annually. So information included in the *TYNDP* usually lags the *ETYS* and *NOA.*
- A different set of energy scenarios are used for the *TYNDP* compared to the *FES* that informs *ETYS* and *NOA.*
- The *TYNDP* focuses mainly on pan-European projects that meet European Union objectives, such as cross-border trade and European environmental targets.
- Analysis for the *TYNDP* is conducted through collaboration between TSOs within European regional working groups. GB is part of the North Sea group.

You can find more information about the *TYNDP* at **http://tyndp.entsoe.eu/**

# 1.3 *ETYS*, the Network Development Roadmap and the Forward Plan

Our July 2018 Network Development Roadmap set out our ambitious commitments to transform our network planning and deliver greater value for consumers. As part of our new incentives framework, we also publish an annual Forward Plan[7] where we set out timeframes for delivering roadmap commitments.

The revised Forward Plan includes combined roles 3 and 4 to facilitate whole system outcomes and support competition in networks. The *ETYS* and *NOA*, in line with our licence obligations, are part of our baseline delivery against these roles, on top of which there are other commitments to transform our approach.

The changing nature of the electricity system means it is increasingly important to study the transmission network needs beyond that of winter peak. The level of uncertainty through a year of operation has increased because of a significant increase in intermittent renewables and interconnectors. This year we have extended the use of probabilistic techniques across a range of the GB network boundaries, and we include preliminary results in chapter 4.

We are extending our network planning to address regional voltage and stability challenges through our pathfinding projects. These projects are helping us develop the tools and processes we need to assess voltage and stability challenges as part of our long-term planning. We have provided updates to the ongoing voltage year-round assessments in the Mersey Ring and Pennine regions in chapter 3. We have also included the process for high voltage assessment in the 2019/20 *NOA* methodology[4].

Our stability pathfinding project is exploring the benefits and practicalities of applying a *NOA*-type approach to the operability aspects of system stability. This is in response to the decline in transmission connected synchronous generation over the next decade. Further detail on our pathfinding projects is available on our dedicated Network Development Roadmap website[5].

We are also aiming to expand the *NOA* process to allow network and non-network solution providers across distribution and transmission to submit options to meet transmission network needs. Our pathfinding projects will provide better data to ensure the right balance between operational and network investment solutions and will increase the value of *ETYS* and *NOA* for consumers.

Finally, we are taking steps to communicate clearly our analysis of transmission network needs to the new audience. We have made the System Requirements Form[6] publicly available but we would welcome feedback on how this *ETYS* document and the way we set out transmission network needs can be more accessible.

[4] https://www.nationalgrideso.com/document/143311/download

[5] https://www.nationalgrideso.com/insights/network-options-assessment-noa/network-development-roadmap

[6] https://www.nationalgrideso.com/document/149751/download

[7] https://www.nationalgrideso.com/about-us/business-planning-riio/forward-plans-2021

# 1.4 Improving your experience

We hope you will benefit from the *ETYS* 2019 and our other ESO publications, the *NOA*, *FES* and *SOF*.

We are keen to hear your views. This year, we received feedback through an online consultation survey, face-to-face at our commercial solutions event, as well as via our *ETYS* email address.

In your feedback, you have asked us to describe transmission system needs more clearly and precisely. We are using our ongoing pathfinding projects to explore how we can better communicate system needs such as voltage and stability. We will use learning from these projects to shape future *ETYS* publications.

We have expanded our probabilistic year-round analysis this year to assess more *ETYS* boundaries. In a dedicated chapter, we explore new ways of presenting thermal year-round results and welcome your feedback on this.

We have also made the System Requirements Form (SRF) publicly available as a workbook on our website as a first step in our pathway to facilitate options from a broader range of participants. We recognise, however, that we need to review our information and processes, including the SRF, to make them more accessible to a broader range of participants and we welcome your views on this.

# Chapter 2
## Network development inputs

## To identify the future transmission requirements of the National Electricity Transmission System (NETS) we must first understand the power demand and generation that may connect to the network. We do this by using the *Future Energy Scenarios (FES)*.

We engage with our customers and stakeholders in a variety of ways, including workshops, webinars and meetings. The feedback we receive is fundamental to the development of *FES* which inform our network planning.

# 2.1 *Future Energy Scenarios (FES)*

During 2018, we engaged with over 630 individual stakeholders from 415 organisations. We received a huge amount of feedback on our *FES 2018* and the scenario framework. Most stakeholders stressed the need for consistency across our analysis from year to year and stated that they would prefer the scenario framework from *FES 2018* to continue. As such, the scenarios and framework remain unchanged for *FES 2019*.

The four scenarios are aligned to the following axes:

- speed of decarbonisation
- level of decentralisation.

**The speed of decarbonisation axis represents the take-up of low-carbon solutions driven by policy, economic and technological factors, and consumer sentiment. All scenarios show progress towards decarbonisation, with Community Renewables and Two Degrees meeting the 2050 target of an 80 per cent reduction in greenhouse gas emissions compared to 1990 levels[1].**

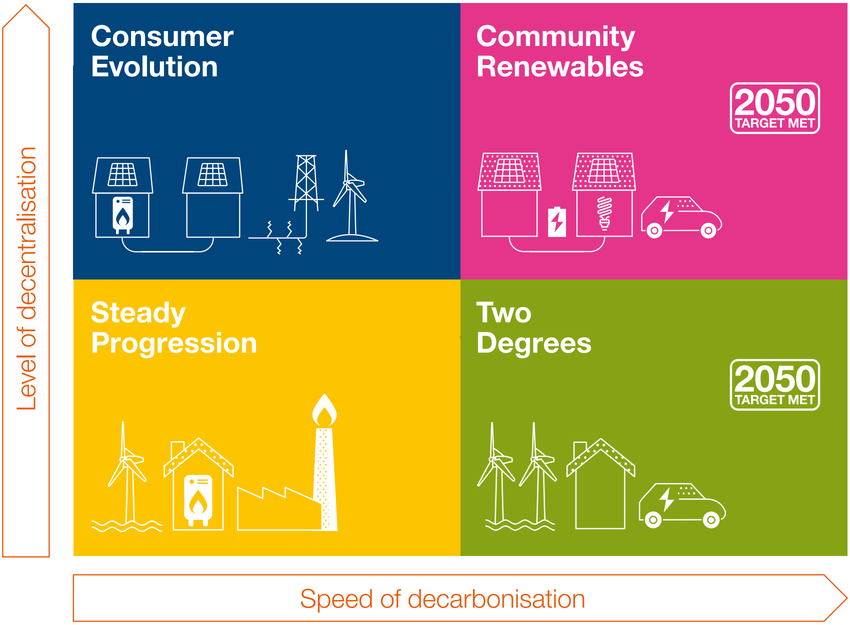
**The level of decentralisation axis indicates how close energy supply is to the end consumer, moving up the axis from large-scale and centralised to smaller-scale local solutions. All scenarios show an increase in decentralised energy production compared with today.**

You can find more information about the *FES 2019* on our website[2] and in chapter 2 of the *FES*. Figure 2.1 provides a brief overview of each scenario and its position on the 2x2 matrix.

[1] Note that at the time the scenarios were developed, this was the legally binding target but this has now moved to a net zero by 2050 target. To reflect this, sensitivity analysis was carried out for a net zero pathway in addition to the four scenarios in *FES 2019*.

[2] http://fes.nationalgrid.com/

**Figure 2.1**
The 2019 scenario matrix




### Community Renewables
This scenario achieves the 2050 decarbonisation target in a decentralised energy landscape.

### Two Degrees
This scenario achieves the 2050 decarbonisation target with large-scale centralised solutions.

### Steady Progression
This scenario makes progress towards decarbonisation through a centralised pathway, but does not achieve the 2050 target.

### Consumer Evolution
This scenario makes progress towards decarbonisation through decentralisation, but does not achieve the 2050 target.

# 2.2 Networks

The *FES* data is applied to simulation models of the NETS to analyse their impact on the network and assess its performance. The security and Quality of Supply Standards (SQSS)[3] set out the criteria and methodology for planning the NETS.

Appendix H provides further details about the SQSS and how the generation, demand and interconnector data are processed and applied to the NETS. Diagrams and details of the network models are provided in appendices A and B.

[3] https://www.nationalgrideso.com/codes/security-and-quality-supply-standards

# Chapter 3
## The electricity transmission network

# 3.1 Introduction

## The GB National Electricity Transmission System must continue to adapt and be developed so power can be transported from source to demand, reliably and efficiently.

To make sure this happens, we must understand its capabilities and the future requirements that may be placed upon it. When we assess future requirements, we need to bear in mind that we have a large number of signed contracts for new generation to connect to the NETS. In addition, the development of interconnectors connecting Great Britain to the rest of Europe will have a big impact on future transmission requirements.

In our experience, it is unlikely that all customers will connect exactly as contracted today. We cannot know exactly how much and when generation will close and new generation will connect, so we use our *FES* to help us decide on credible ranges of future NETS requirements and its present capability.

This is done using the system boundary concept. It helps us to calculate the NETS's boundary capabilities and the future transmission requirements of bulk power transfer capability. The transmission system is split by boundaries[1] that cross important power-flow paths where there are limitations to capability or where we expect additional bulk power transfer capability will be needed. We apply the SQSS[2] to work out the NETS boundary requirements.

In this chapter, we describe the NETS characteristics. We also discuss each of the NETS boundaries, grouped together as regions, to help you gain an overview of the total requirements, both regionally and by boundary.

This chapter also provides analysis to show you how, and when, in the years to come, the NETS will potentially face growing future network needs on a number of its boundary regions. We also provide updates on our high voltage pathfinding project.

The results presented in this chapter will be used in the *NOA 2019/20* to present an assessment of the ESO's recommended reinforcement options to address the potential future NETS boundary needs.

[1] Please note that these boundaries will be reviewed annually and updated as appropriate.

[2] https://www.nationalgrideso.com/codes/security-and-quality-supply-standards

# 3.2 NETS background

## The NETS is mainly made up of 400kV, 275kV and 132kV assets connecting separately owned generators, interconnectors, large demands and distribution systems.

As the ESO, we are responsible for managing the system operation of the transmission networks in England, Wales, Scotland and offshore. The 'transmission' classification applies to assets at 132kV or above in Scotland or offshore. In England and Wales, it relates mainly to assets at 275kV and above.

National Grid Electricity Transmission owns the transmission network in England and Wales. The transmission network in Scotland is owned by two separate transmission companies: Scottish Hydro Electric Transmission in the north of Scotland and SP Transmission in the south of Scotland.

The offshore transmission systems are also separately owned. Seventeen licenced offshore transmission owners (OFTOs)[3] have been appointed through the transitional tendering process. They connect operational offshore wind farms that were given Crown Estate seabed leases in allocation rounds.

[3] https://www.ofgem.gov.uk/system/files/docs/2019/08/electricity_registered_or_service_addresses_new.pdf

# 3.3 NETS boundaries

**To provide an overview of existing and future transmission requirements, and report the restrictions we will see on the NETS, we use the concept of boundaries. A boundary splits the system into two parts, crossing critical circuit paths that carry power between the areas where power flow limitations may be encountered.**

The transmission network is designed to make sure there is enough transmission capacity to send power from areas of generation to areas of demand.

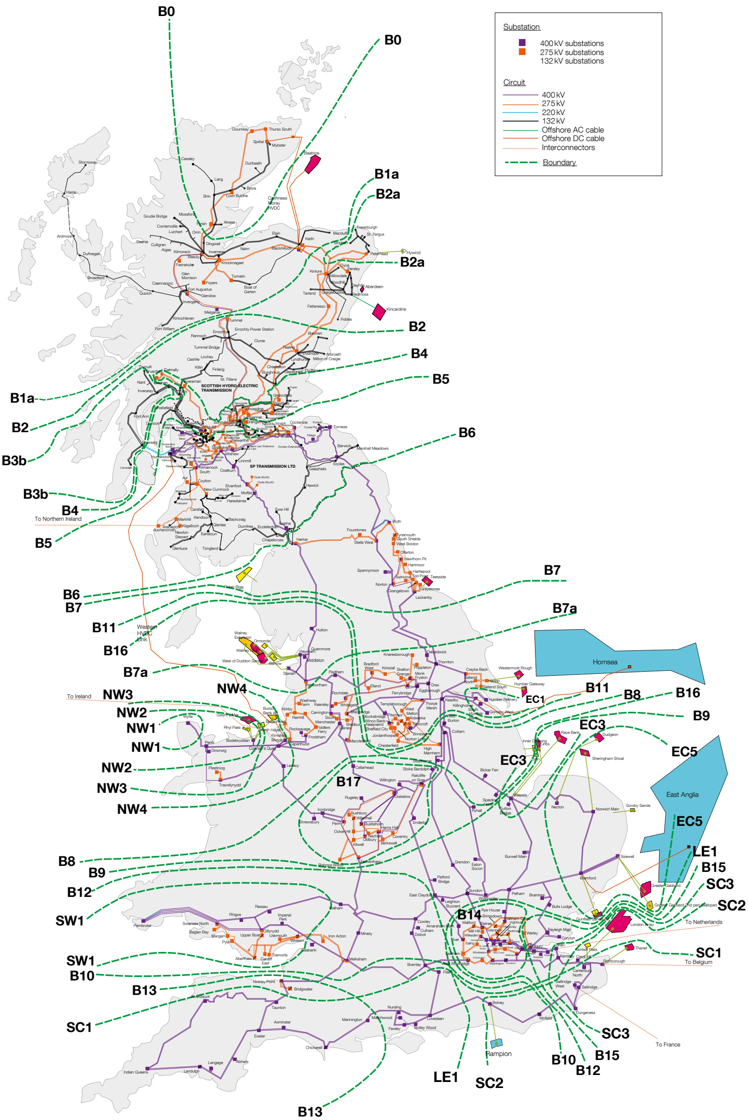
Limiting factors on transmission capacity include thermal circuit rating, voltage constraints and dynamic stability. From the network assessment, the lowest known limitation is used to determine the network boundary capability. The base capability of each boundary in this document refers to the capability expected for winter 2019/20.

Defining the NETS boundaries has taken many years of operation and planning experience of the transmission system. The NETS's boundaries have developed around major sources of generation, significant route corridors and major demand centres. A number of recognised boundaries are regularly reported for consistency and comparison purposes. When significant transmission system changes occur, new boundaries may be defined and some existing boundaries either removed or amended (an explanation will be given for any changes). Some boundaries are also reviewed but not studied because of no significant changes in the *FES* generation and demand data of the area from the previous years. For such boundaries, the same capability as the previous year is assumed.

### GB NETS boundary map

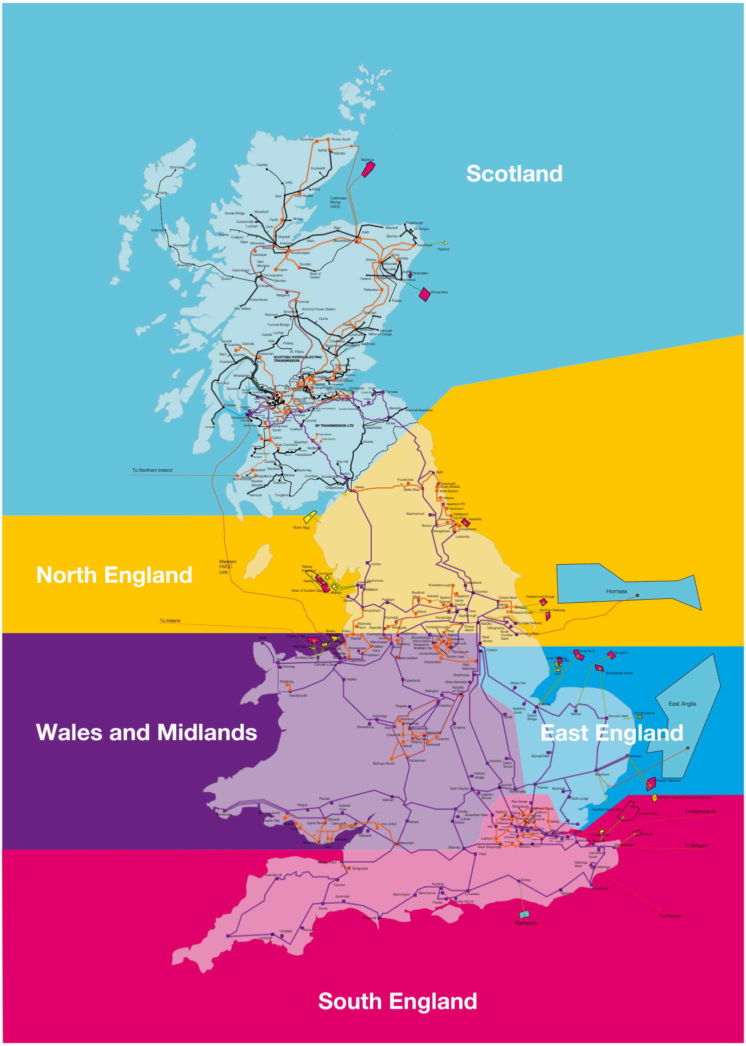
Figure 3.1 shows all the boundaries we have considered for our *ETYS* analysis. Over the years, we have continuously developed the transmission network to ensure there is sufficient transmission capacity to effectively transport power across the country.

## Figure 3.1
GB NETS boundaries



To help describe related issues, we have grouped the boundaries into five regions, as shown in figure 3.2.

**Figure 3.2**
Regional map



## Determining the present capability and future requirements of the NETS boundaries

The boundaries used by *ETYS* and *NOA* can be split into two different types:

**Local boundaries –** are those which encompass small areas of the NETS with high concentration of generation. These small power export areas can give high probability of overloading the local transmission network due to coincidental generation operation.

**Wider boundaries –** are those that split the NETS into large areas containing significant amounts of both generation and demand. The SQSS boundary scaling methodologies are used to assess the network capability of the wider boundaries. These methodologies take into account both the geographical and technological effects of generation. This allows for a fair and consistent capability and requirements assessment of the NETS. The NETS SQSS defines the methodology to assess boundary planning requirements, based on the economy and security criteria.

- **The security criterion –** evaluates the NETS's boundary transfer requirements to satisfy demand without reliance on intermittent generators or imports from interconnectors. The relevant methodology for determining the security needs and capability are from the SQSS Appendices C and D.
- **The economy criterion –** defines the NETS's boundary transfer requirements when demand is met with high output from intermittent and low-carbon generators and imports from interconnectors. This is to ensure that transmission capacity is adequate to transmit power from the highly variable generation types without undue constraint. The relevant methodology for determining the economy needs and capability are from the SQSS Appendices E and F.

## Interpreting the boundary graphs

The graphs show a distribution of power flow for each scenario, in addition to the boundary power transfer capability and NETS SQSS requirements for the next twenty years. Using the B6 boundary charts as an example (figure 3.3), it can be seen that a separate chart is provided for each of the four future energy scenarios. Each scenario has different generation and demand so produces different boundary power flow expectations.

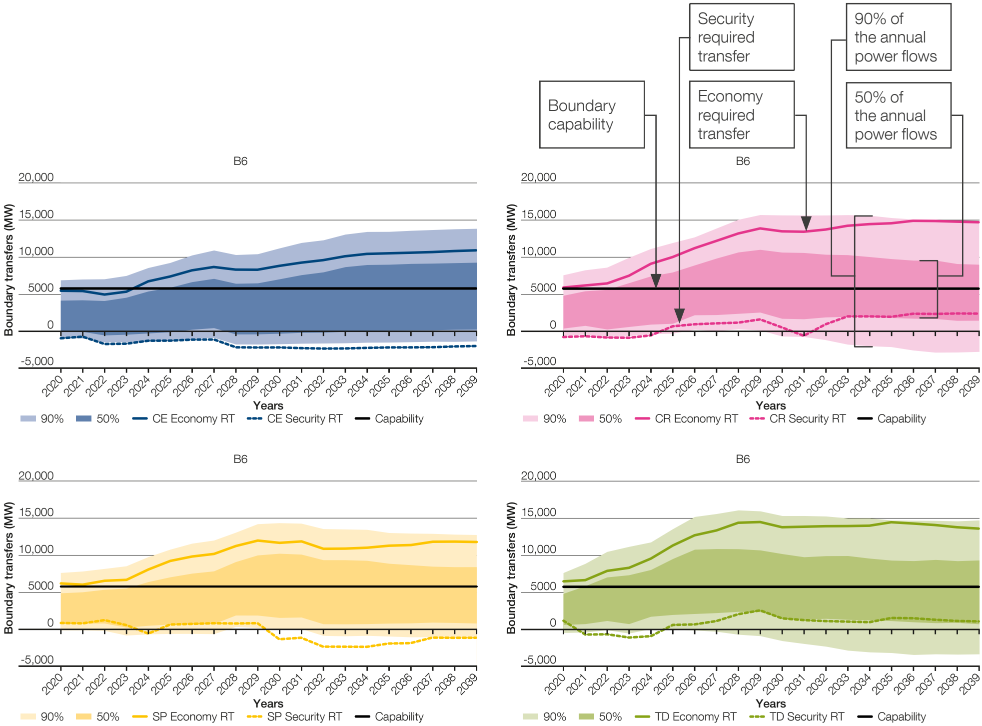
The NETS SQSS sets the methodology to set the wider boundary planning requirements, i.e. the economy and security criteria discussed above. These are shown in the graphs as a solid coloured line for economy required transfer and a dashed coloured line for security required transfer.

Boundary capability, in accordance with NETS SQSS requirements, is represented as a solid flat line on the graphs. The line position is calculated to represent the expected boundary capability for the coming 2019/20 winter peak. The boundary capability will change over time as the network, generation and demand change, all of which are uncertain. Therefore, to show system future needs and opportunities for each boundary a single straight capability line based on the present conditions is shown.

Two shaded areas are now shown on each boundary graph which represents the distribution of annual power flow. The darker shaded area shows an area in which 50 per cent of the annual power flows lie. In percentile terms, 75 per cent of annual power flows are lower than the upper edge of the dark shaded area and 75 per cent are higher than the lower edge. The lighter and darker shaded areas together show an area in which 90 per cent of the annual power flows lie. In percentile terms, 95 per cent of annual power flows are lower than the upper edge of the lightly shaded area and 95 per cent are higher than the lower edge.

The calculations of the annual boundary flow are based on unconstrained market operation, meaning network restrictions are not applied. This way, the minimum cost generation output profile can be found. By looking at the free market power flows in comparison with boundary capability, it can be seen where future growing needs can be expected.

**Figure 3.3**
Example of boundary transfer graphs and base capability for a boundary



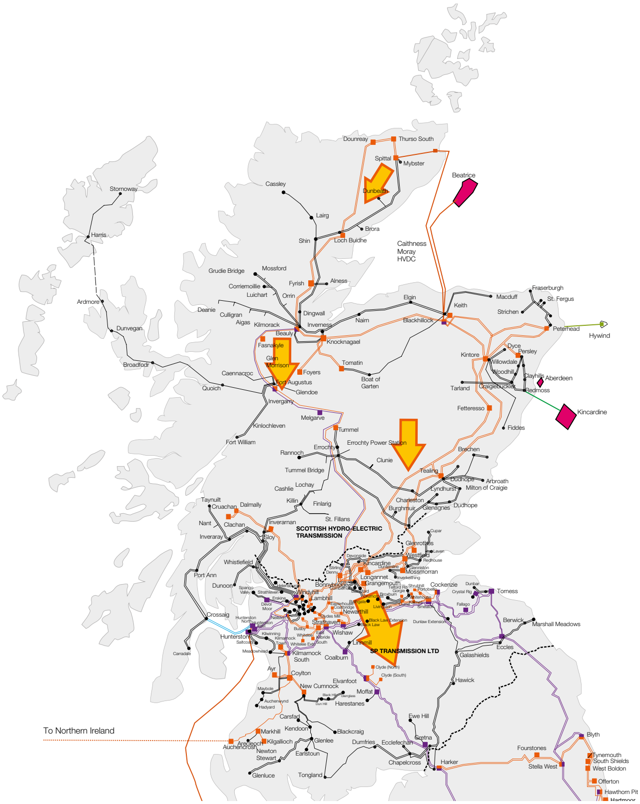

**Stakeholder engagement**
If you have feedback on any of the content of this document, please send it to **transmission.etys@nationalgrideso.com**, catch up with us at one of our consultation events or visit us at National Grid ESO, Faraday House, Warwick.

# 3.4 Network capability and requirements by region – Scottish boundaries

## Introduction

The following chapter describes the Scottish transmission networks up to the transmission ownership boundary with the England and Wales transmission network. The onshore transmission network in Scotland is owned by SHE Transmission and SP Transmission. The Scottish NETS is divided by boundaries B0, B1a, B2, B3b, B4, B5 and B6. The B4 boundary is shared by SHE Transmission and SP Transmission. The B6 boundary is shared by SP Transmission and National Grid Electricity Transmission. The figure below shows the general pattern of power flow directions expected to occur most of the time in the years to come up to 2029, i.e. power will generally flow from north to south. The arrows in the diagram illustrate power flow directions and are approximately scaled relative to the winter peak flows. The flow of power is largely dependent on the output from wind and other generation sources in Scotland. There will be times, most likely when wind is low and demand is high, when power will flow from south to north.

**Figure SR.1**
Scottish transmission network and the typical direction of power flows



## Primary challenge statement:

Scotland is experiencing large growth in renewable generation capacity, often in areas where the electricity network is limited.

## Regional drivers

The rapidly increasing generation capacity, mostly from renewable sources and mainly wind, connecting within Scotland is leading to future growing needs in some areas. Across all the *FES*, the fossil fuel generating capacity in Scotland reaches nearly zero. In all but the **Consumer Evolution** scenario, interconnector and storage capacity increases. By 2035, the scenarios (shown in figure SR.2) suggest a total Scottish generating capacity of between 18 and 30 GW. The reduction in synchronous generation could lead to challenges with reduced short circuit levels and inertia. This potentially leads to increasingly dynamic Scottish network behaviour depending on factors such as weather condition and price of electricity. With gross demand in Scotland not expected to exceed 6 GW (shown in figure SR.3) by 2040, which is much less than the Scottish generation capacity, Scotland will be expected to export power into England most of the time. At times of low renewable output, Scotland may need to import power from England. In a highly decentralised scenario like **Community Renewables**, local generation capacity connected at the distribution level in the Scotland region could reach more than 11 GW by 2040. Of that capacity, the typical total embedded generation output might be around 4 GW on average. This will vary depending on factors like wind speeds, and how other local generators decide to participate in the market.

**Figure SR.2**
Generation capacity mix scenarios for Scotland

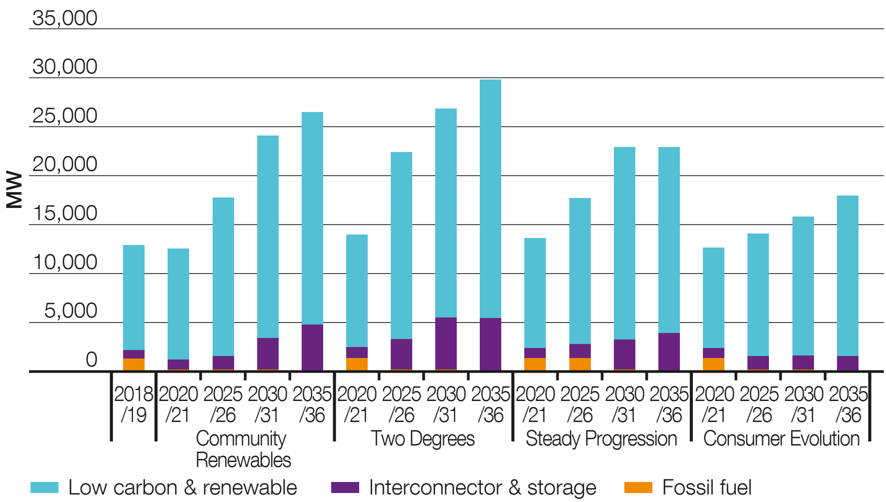
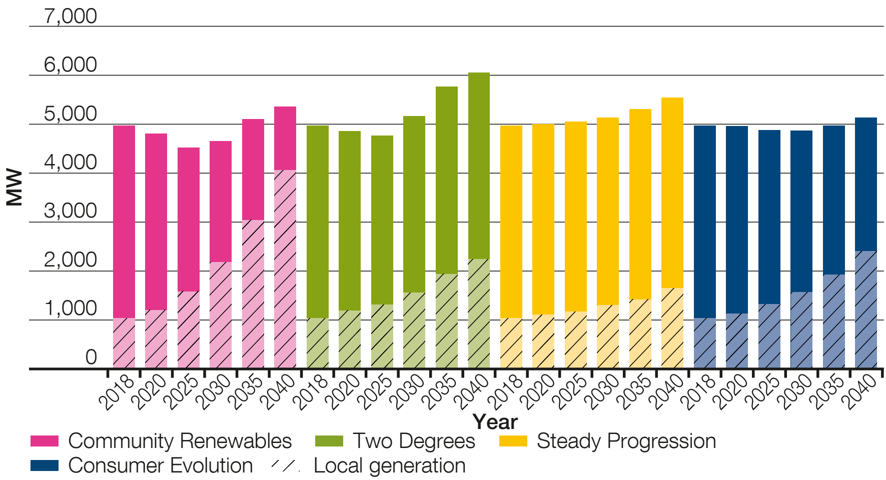


**Figure SR.3**
Gross demand scenarios for Scotland




The anticipated increase in renewable generation in Scotland is increasing power transfer across the Scottish boundaries. On a local basis, with the anticipated generation development in the north of Scotland, including generation developments on the Western Isles, Orkney and the Shetland Islands, there may be limitations on power transfer from generation in the remote Scottish NETS locations to the main transmission routes (B0, B1a).

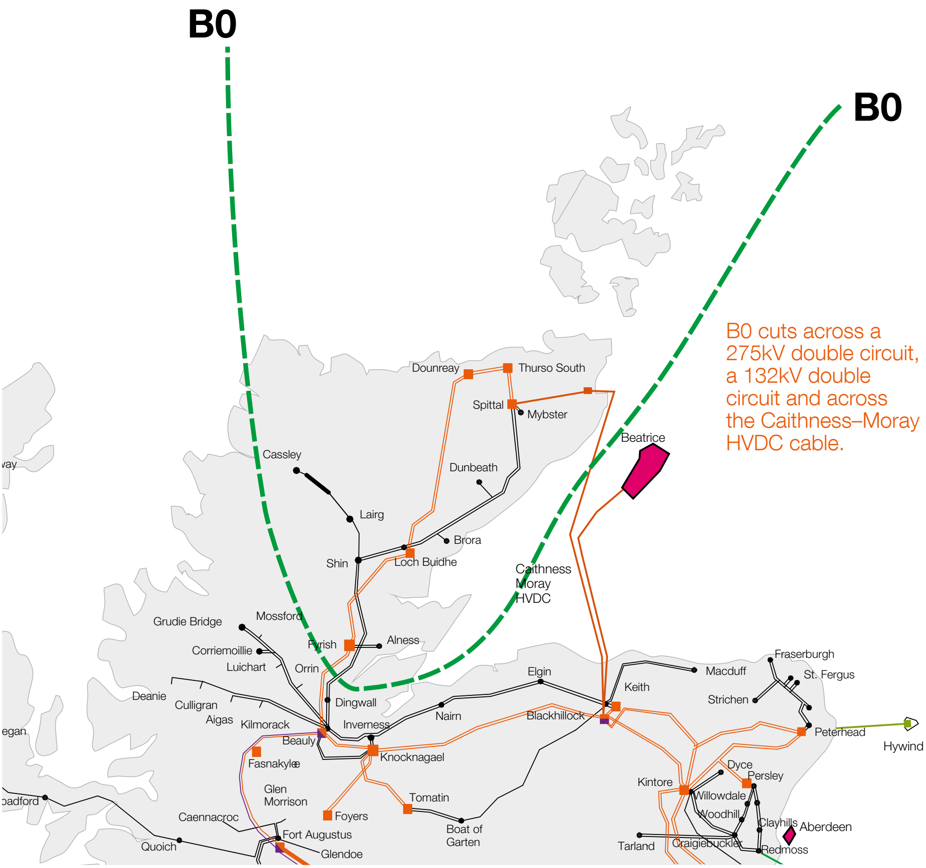
The Argyll and the Kintyre peninsula is an area with significant renewable generation activity and low demand. A boundary assessment is needed to show potential for high generation output and network limitations to power flows on this part of the NETS (B3b).

As generation within these areas increases over time, due to the high volume of new renewable generation seeking connection, boundary transfers across the Scottish NETS boundaries (B0, B1a, B2, B3b, B4 and B5 and B6) increase.

The need for network reinforcement to address the above mentioned potential capability issues will be evaluated in the *NOA 2019/20* CBA. Following the evaluation, the preferred reinforcements for the Scotland region will be recommended.

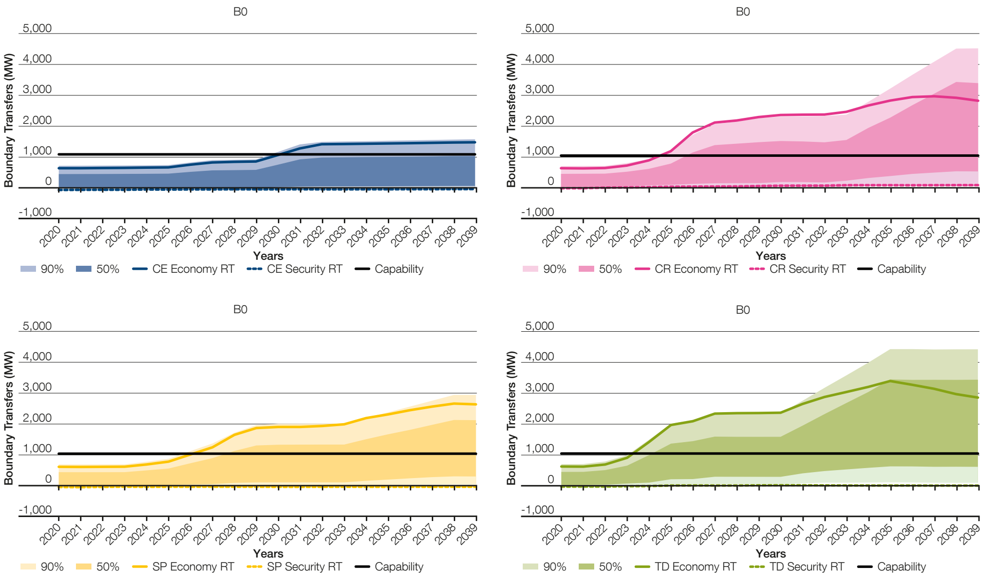
# Boundary B0 – Upper North SHE Transmission

**Figure B0.1**
Geographic representation of boundary B0




Boundary B0 separates the area north of Beauly, comprising the north of the Highlands, Caithness, Sutherland and Orkney. The Caithness–Moray HVDC subsea cable, and associated onshore works, completed in December 2018, significantly strengthen the transmission network north of Beauly.

**Figure B0.2**
Boundary flows and base capability for boundary B0



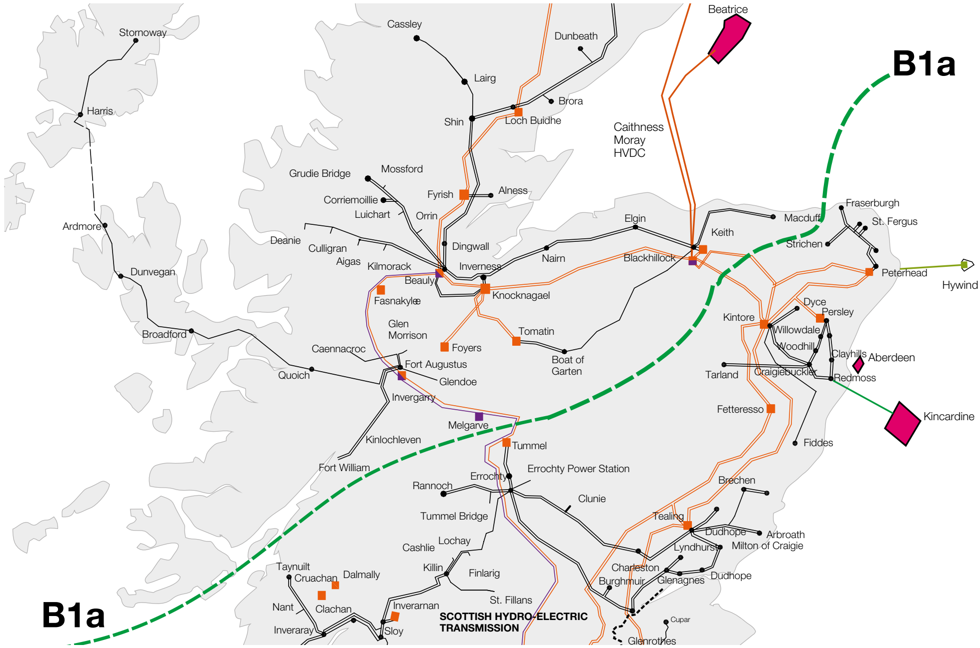

## Boundary requirements and capability

Figure B0.2 above shows the projected boundary flows for B0 for the next 20 years. The current boundary capability is limited to around 1.0 GW, due to a thermal constraint.

The power transfer through B0 is increasing due to the substantial growth of renewable generation north of the boundary. This generation is primarily onshore wind, with the prospect of significant marine generation resource in the Pentland Firth and Orkney waters in the longer term.

# Boundary B1a – North West SHE Transmission

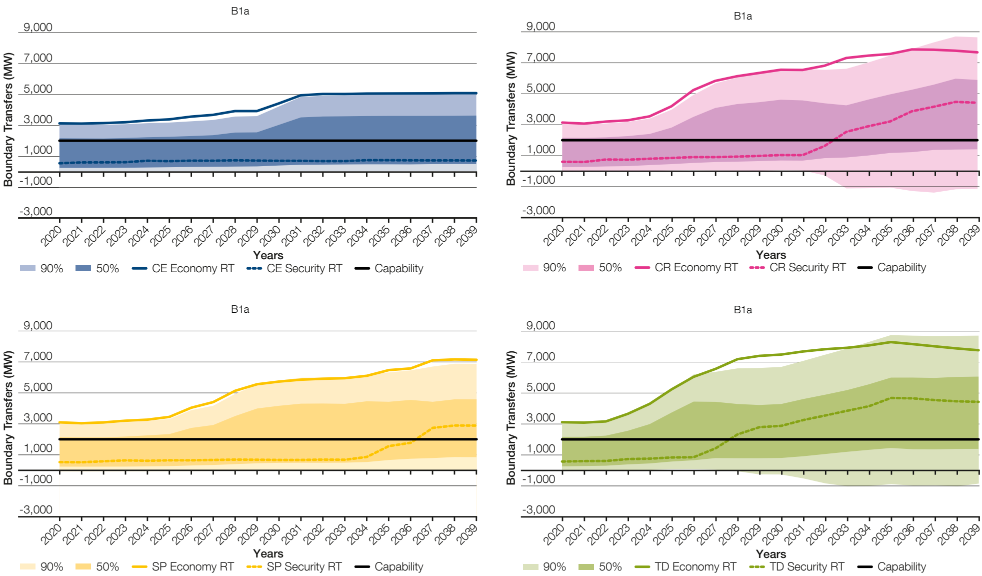
**Figure B1a.1**
Geographic representation of boundary B1a




B1a crosses two 275kV double circuits and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B1a runs from the Moray coast near Macduff to the west coast near Oban, separating the north west of Scotland from the southern and eastern regions. High renewables output causes high transfers across this boundary.

## Figure B1a.2
Boundary flows and base capability for boundary B1a




## Boundary requirements and capability

Figure B1a.2 above shows the projected boundary flows for B1a for the next 20 years. The boundary capability is currently limited to around 2.3 GW due to a thermal constraint.

New renewable generation connections north of the boundary are expected to result in a significant increase in export requirements across the boundary. All generation north of boundary B0 also lies behind boundary B1a.

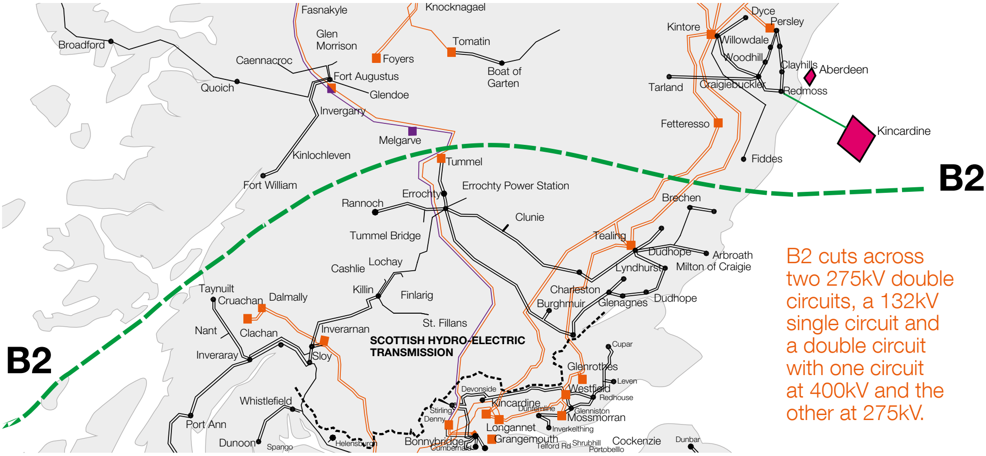
In all the future energy scenarios, there is an increase in the power transfer through B1a due to the large volume of renewable generation connecting to the north of this boundary.

Although this is primarily onshore wind and hydro, there is the prospect of significant additional wind, wave and tidal generation resources being connected in the longer term. Contracted generation behind boundary B1a includes the renewable generation on the Western Isles, Orkney and the Shetland Isles with a considerable volume of large and small onshore wind developments.

A large new pump storage generator is also planned in the Fort Augustus area. Some marine generation is also expected to connect in this region during the ETYS period. This is supplemented by existing generation, which comprises around 800 MW of hydro and 300 MW of pumped storage at Foyers.

# Boundary B2 – North to South SHE Transmission

**Figure B2.1**
Geographic representation of boundary B2

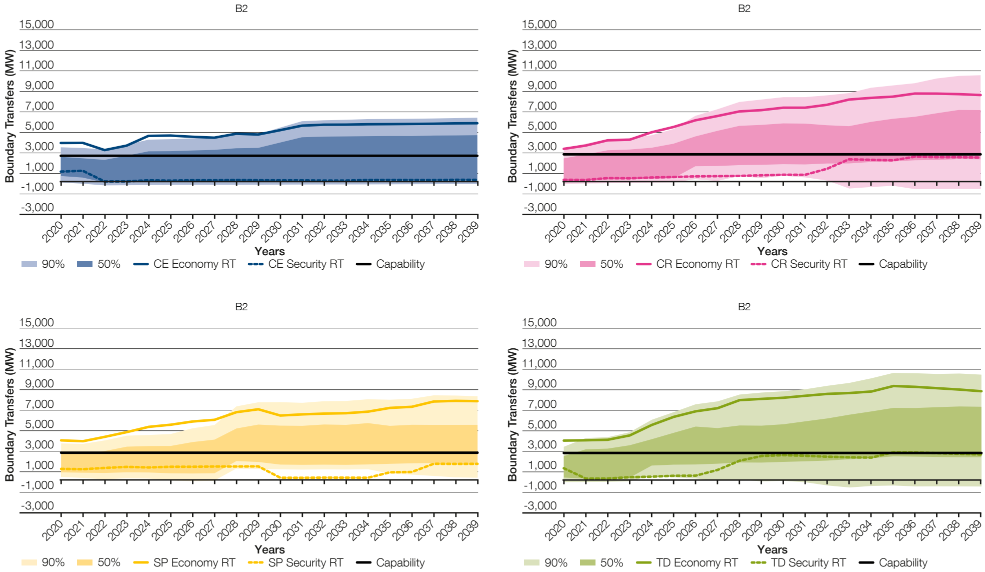



B2 cuts across two 275kV double circuits, a 132kV single circuit and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B2 cuts across the Scottish mainland from the east coast between Aberdeen and Dundee to near Oban on the west coast. As a result, it crosses all the main north-south transmission routes from the north of Scotland.

The generation behind boundary B2 includes both onshore and offshore wind, with the prospect of significant marine generation resource being connected in the longer term. There is also the potential for additional pumped storage plant to be located in the Fort Augustus area. The thermal generation at Peterhead lies between boundaries B1a and B2, as do several offshore windfarms and the proposed future North Connect interconnector with Norway.

## Figure B2.2
Boundary flows and base capability for boundary B2




## Boundary requirements and capability

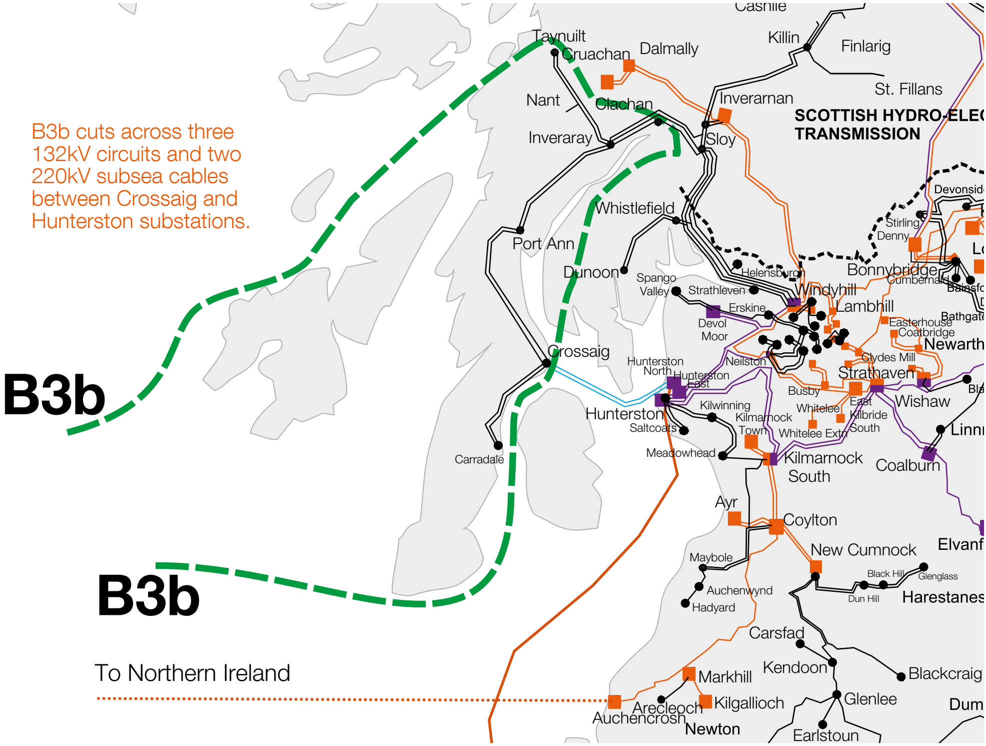
Figure B2.2 above shows the projected boundary flows for B2 for the next 20 years. The boundary capability is currently limited to around 2.7 GW due to a thermal constraint.

The potential future boundary transfers for boundary B2 are increasing at a significant rate because of the high volume of renewable generation to be connected to the north of the boundary.

The increase in the required transfer capability for this boundary across all generation scenarios indicates the strong potential need to reinforce the transmission system.

# Boundary B3b – Kintyre and Argyll SHE Transmission

**Figure B3b.1**
Geographic representation of boundary B3b

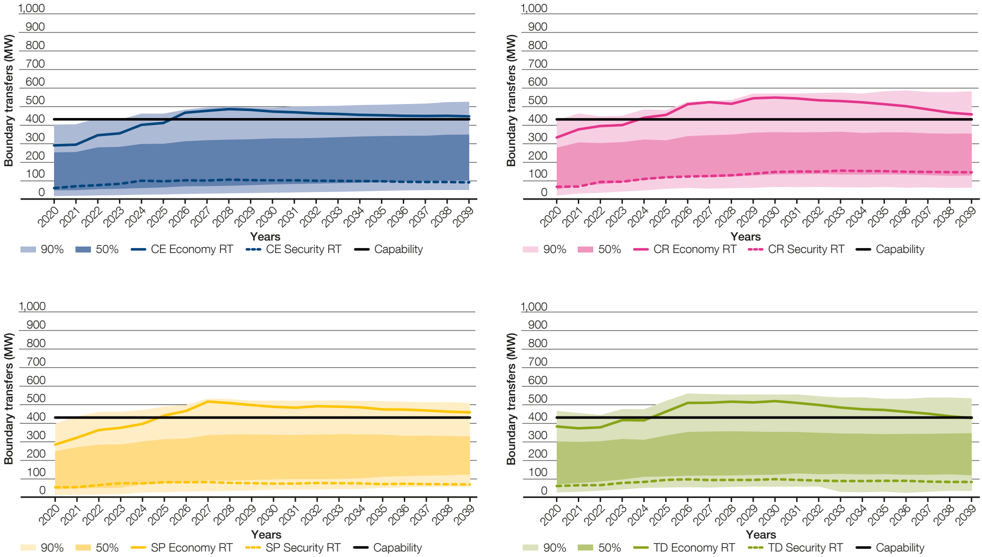



Boundary B3b encompasses the Argyll and Kintyre peninsula, and boundary assessments are used to show limitations on the generation power flow out of the peninsula.

The generation within boundary B3b includes both onshore wind and hydro generation, with the prospect of further wind generation resource and the potential for marine generation being connected in B3b in the future, triggering the requirement for future reinforcement of this network.

## Figure B3b.2

Boundary flows and base capability for boundary B3b




## Boundary requirements and capability

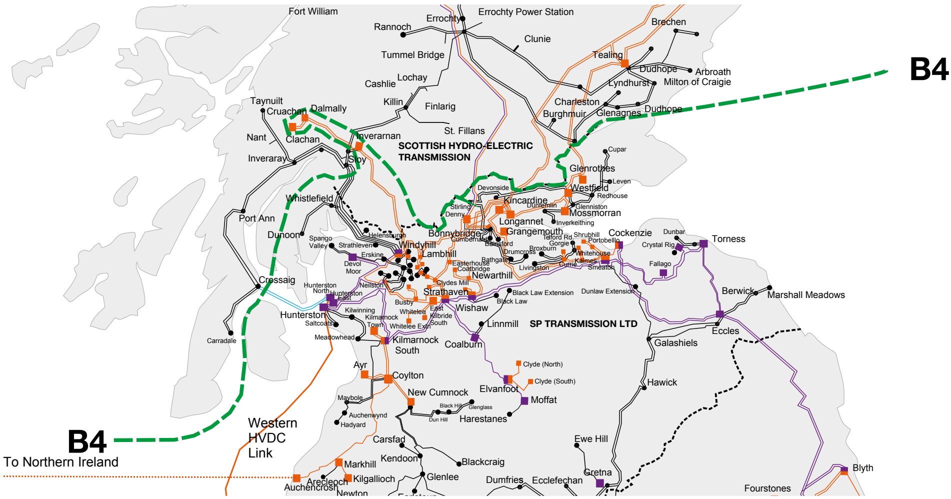
Figure B3b.2 above shows the projected boundary flows for B3b for the next 20 years. The boundary capability is currently limited to around 0.43 GW due to a thermal constraint.

In all of the FES, the power transfer across boundary B3b increases because of potential generation connecting within the boundary. This is primarily onshore wind generation, with the prospect of marine generation resource being connected as well.

The increase in the potential required transfer capability indicates the potential need to reinforce the transmission network across boundary B3b.

# Boundary B4 – SHE Transmission to SP Transmission

**Figure B4.1**
Geographic representation of boundary B4

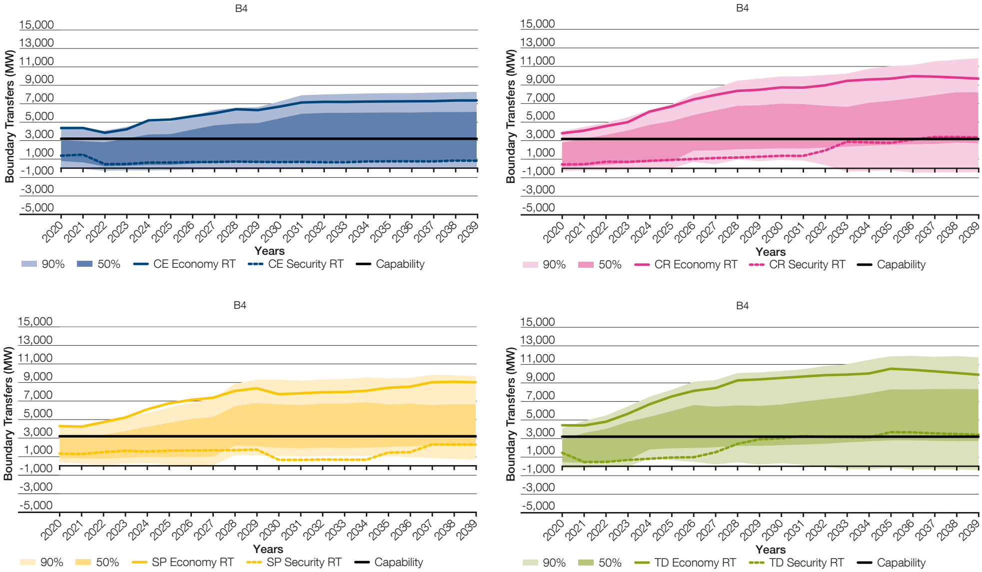



B4 cuts across two 275kV double circuits, two 132kV double circuits, two 275/132kV auto-transformer circuits, two 220kV subsea cables between Crossaig and Hunterston substations, and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B4 separates the transmission network at the SP Transmission and SHE Transmission interface running from the Firth of Tay in the east to the north of the Isle of Arran in the west. With increasing generation and potential interconnectors in the SHE Transmission area for all scenarios, the required transfer across boundary B4 is expected to increase significantly over the *ETYS* period.

The prospective generation behind boundary B4 includes around 2.7 GW from Rounds 1–3 and Scottish territorial waters offshore wind located off the coast of Scotland.

## Figure B4.2
Boundary flows and base capability for boundary B4



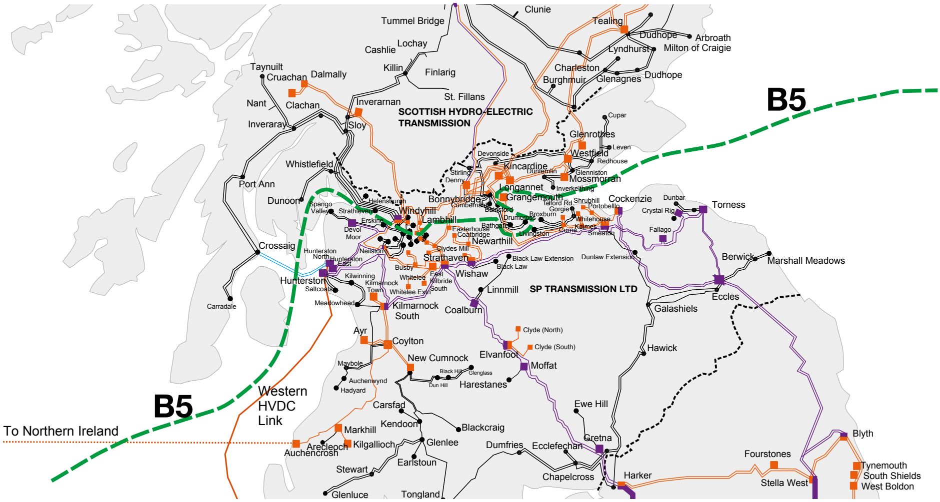

## Boundary requirements and capability

Figure B4.2 above shows the projected boundary flows for B4 for the next 20 years. The current boundary capability is limited to around 3.1 GW due to a thermal constraint.

In all of the FES, the power transfer through boundary B4 increases because of the significant volumes of generation connecting north of the boundary, including all generation above boundaries B0, B1a, B2 and B3b. This is primarily onshore and offshore wind generation, with the prospect of significant marine generation resource being connected in the longer term.

# Boundary B5 – North to South SP Transmission

**Figure B5.1**
Geographic representation of boundary B5

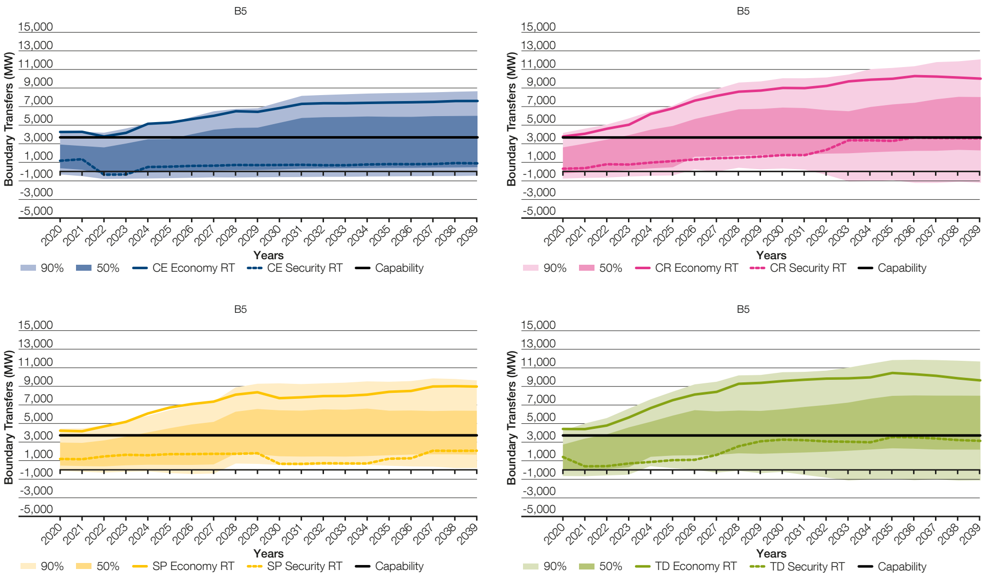



B5 cuts across three 275kV double circuits and a double circuit with one circuit at 400kV and the other at 275kV. The Kintyre–Hunterston subsea link provides two additional circuits crossing B5.

Boundary B5 is internal to the SP Transmission system and runs from the Firth of Clyde in the west to the Firth of Forth in the east.

The generating station at Cruachan, together with the demand groups served from Windyhill, Lambhill, Bonnybridge, Mossmorran and Westfield 275kV substations are located to the north of boundary B5.

## Figure B5.2
Boundary flows and base capability for boundary B5



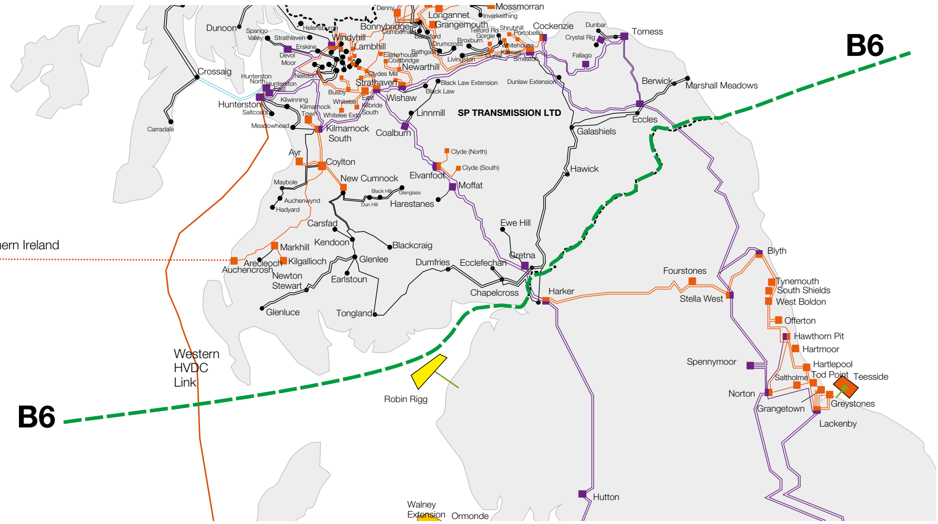

## Boundary requirements and capability

Figure B5.2 above shows the projected boundary flows for B5 for the next 20 years. The capability of the boundary is presently limited by both thermal and voltage constraints to around 3.7 GW.

In all the FES, the power transfer through boundary B5 increases because of the significant volumes of generation connecting north of the boundary, including all generation above boundaries B0, B1a, B2 and B4. This is primarily onshore and offshore wind generation.

# Boundary B6 – SP Transmission to NGET

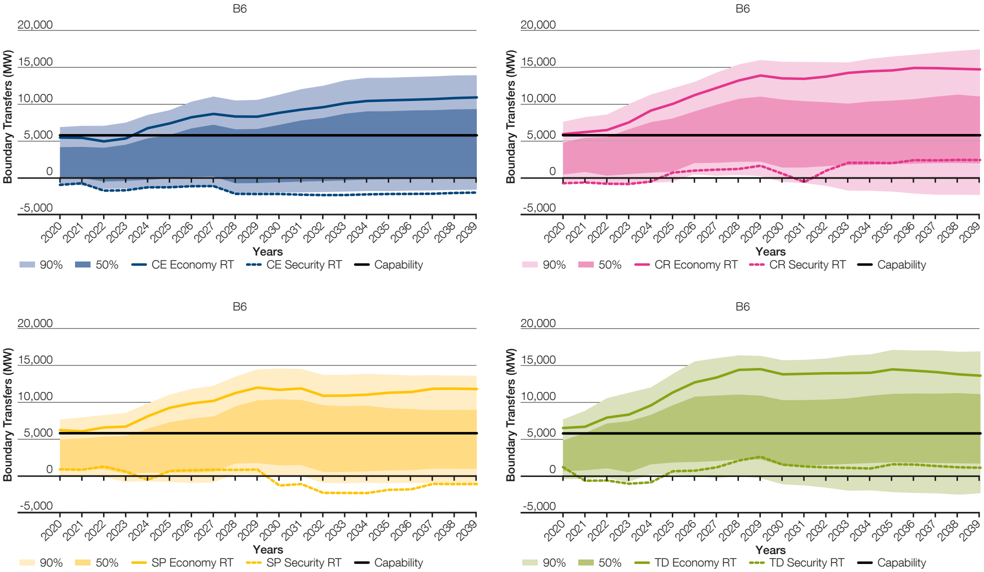
**Figure B6.1**
Geographic representation of boundary B6




B6 cuts across two 400kV double circuits.
The Western HVDC link also crosses the boundary.

Boundary B6 separates the SP Transmission and the National Grid Electricity Transmission (NGET) systems. Scotland contains significantly more installed generation capacity than demand, increasingly from wind farms. Peak power flow requirements are typically from north to south at times of high renewable generation output.

## Figure B6.2
Boundary flows and base capability for boundary B6




## Boundary requirements and capability

Figure B6.2 above shows the projected boundary power flows crossing B6 for the next 20 years. The boundary capability remains at 5.7 GW with the limit being the post-fault load rating of transformers at Harker.

Across all FES, there is an increase in the power transfer requirements from Scotland to England due to the connection of additional generation in Scotland, primarily onshore and offshore wind. This generation increase is partially offset by the expected closure of nuclear plants, the timing of which varies in each scenario.

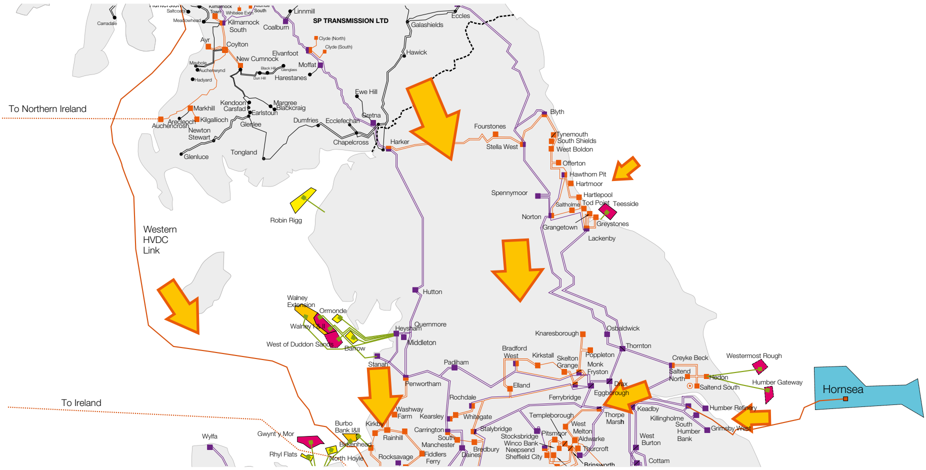
With the FES including many wind farms in Scotland, the spread of boundary power flows is very wide due to the intermittent nature of the wind. With low generation output in Scotland, it is credible to have power flowing from south to north feeding Scottish demand. The magnitude of the south to north power flows is low compared to those in the opposite direction so network capability should be sufficient to support those conditions. While the south to north transfer capability is enough to meet demand in Scotland, it is still necessary for conventional synchronous generation to remain in service in Scotland to maintain year-round secure system operation.

# 3.5 Network capability and requirements by region – The North of England boundaries

## Introduction

The North of England transmission region includes the transmission network between the Scottish border and the north Midlands. This includes the upper north boundaries B7, B7a and B8. The figure below shows likely power flow directions at system winter peak.

**Figure NE.1**
North of England transmission network



## Primary challenge statement:

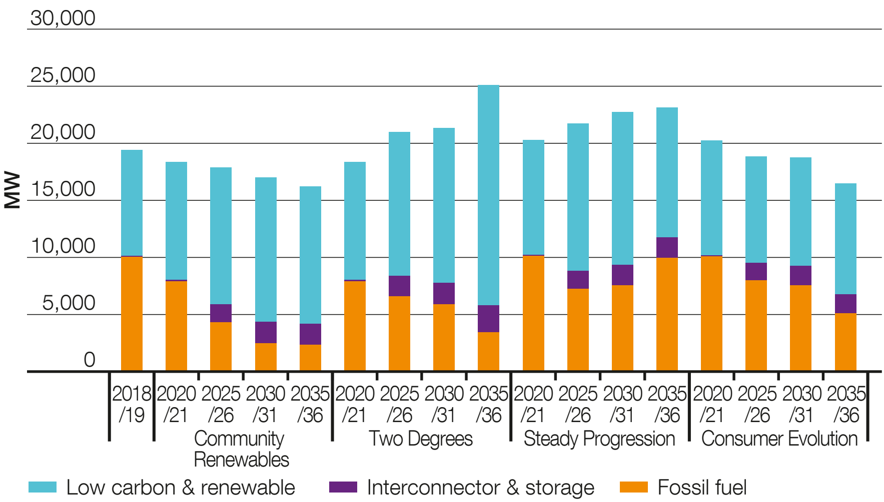
The connection of large amounts of new generation, most of which is intermittent renewables, in Scotland and the north will cause overloading in the northern transmission network unless appropriate reinforcements are in place. Future power transfer requirements could be more than double compared to what they are today in some scenarios.

## Regional drivers

The future energy scenarios suggest the northern transmission region could see a range of changes as shown in the graph below (figure NE.2). All four scenarios suggest growth in low-carbon and renewable generation, in addition to new storage and interconnector developments. The connected fossil fuel generation could see sustained decline in all but the **Steady Progression** scenario. Large connections could cause network issues if connected to the north region.

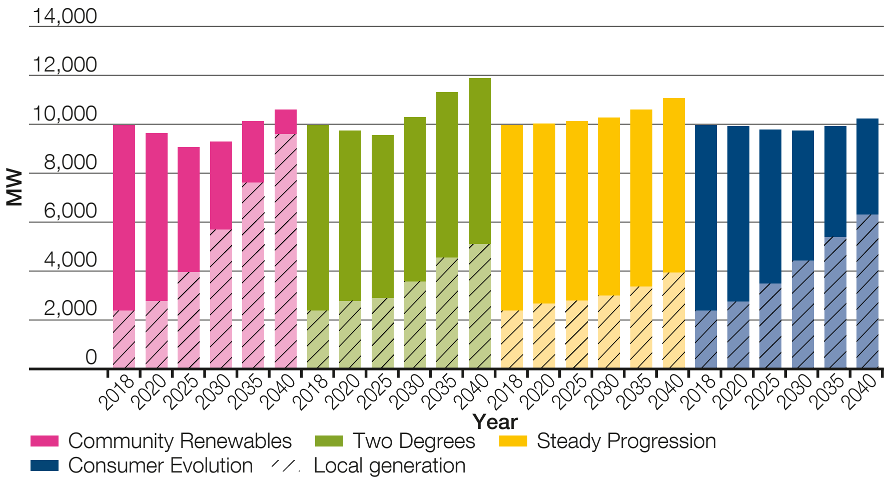
## Figure NE.2

Generation capacity mix scenarios for the North of England




The gross demand in the region, as shown in figure NE.3, could reasonably be expected to increase as can be seen for all scenarios. The amount of embedded local generation is also expected to increase, so the net demand seen by the transmission network could significantly reduce and even become net generation. In a highly decentralised scenario like **Community Renewables**, local generation capacity connected at the distribution level in this northern region could reach more than 23 GW by 2040. Of that capacity, a typical total embedded generation output on average might be around 9.5 GW. This will vary depending on factors like wind speeds, and how other local generators decide to participate in the market.

**Figure NE.3**
Gross demand scenarios for the North of England




Presently, most of the northern transmission network is oriented for north-south power flows with connections for demand and generation along the way. At times of high wind generation, the power flow will mostly be from north to south, with power coming from both internal boundary generation and generation further north in Scotland. When most of this area and Scotland is generating power, the transmission network can be highly overloaded. The loss of one of the north to south routes can have a highly undesirable impact on the remaining circuits.

The highly variable nature of power flows in the north presents challenges to voltage management, and therefore automatic reactive power control switching is utilised. This helps to manage the significant voltage drop due to reactive power demands which arise at times of high levels of power flow on long circuits. Operational reactive switching solutions are also used to manage light loading conditions when the voltage can rise to unacceptable levels.

The high concentration of large conventional generators around Humber and South Yorkshire means that system configuration can be limited by high fault levels. Therefore, some potential network capability restrictions in the north can be due to the inability to configure the network as desired due to fault level concerns.

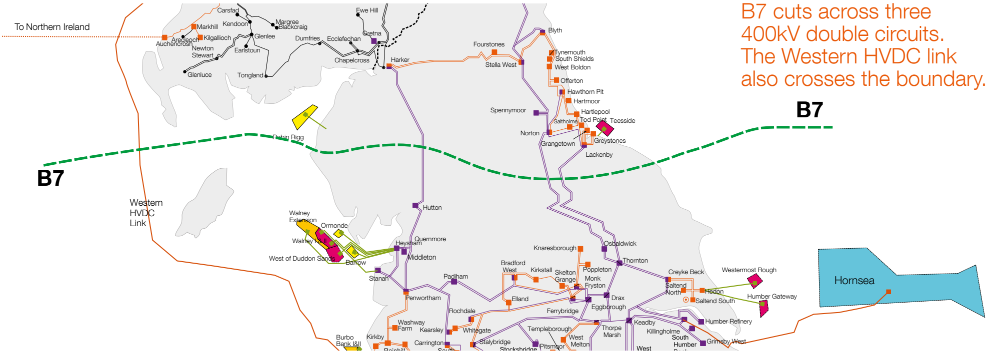
As the potential future requirement to transfer more power from Scotland to England increases, B7 and B7a are likely to reach their capability limits and may need network reinforcement. The potential future restrictions to be overcome across B7 and B7a are summarised:

- Limitation on power transfer out of north east England (boundary B7) is caused by thermal limitation for a fault on the double circuit between Harker–Hutton.
- At high power transfer, thermal limitations occur on a number of circuits within the north east 275kV ring.
- Limitation on power transfer from Cumbria to Lancashire (boundary B7a) occurs due to thermal limitation at Padiham–Penwortham circuit.

The need for network reinforcement to address the above mentioned potential capability issues will be evaluated in the *NOA 2019/20* CBA.

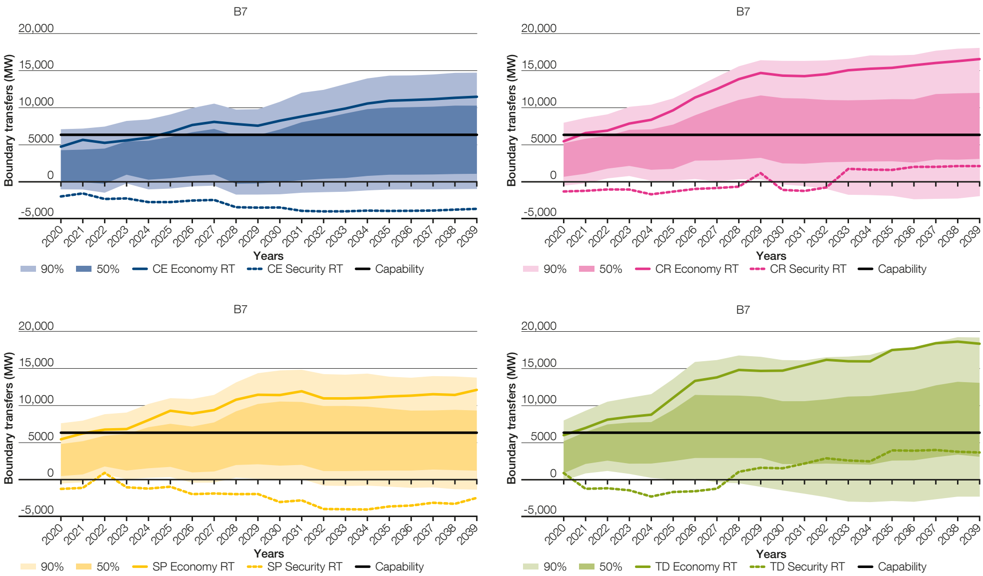
# Boundary B7 – Upper North of England

**Figure B7.1**
Geographic representation of boundary B7




Boundary B7 bisects England south of Teesside. The area between B6 and B7 has been traditionally an exporting area, and constrained by the power flowing through the region from Scotland towards the south with the generation surplus from this area added.

## Figure B7.2
Boundary flows and base capability for boundary B7




### Boundary requirements and capability

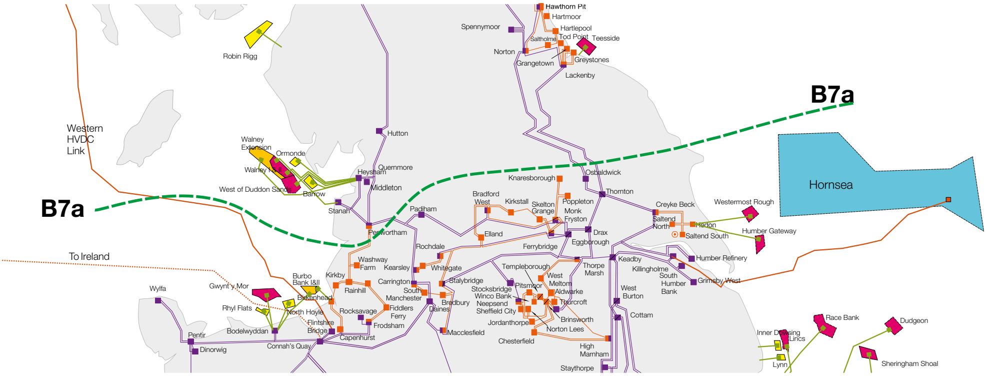
Figure B7.2 above shows the projected boundary power flows crossing B7 for the next 20 years. The boundary capability is 6.3 GW, and is limited thermally by the post-fault load rating of transformers at Harker under the Harker–Hutton double-circuit fault.

The 2019/20 boundary capability is expected to satisfy the NETS SQSS requirements but, for all four FES, the SQSS economy required transfer and expected power flows quickly grow to beyond the present boundary capability. This suggests a strong need for network development to manage the increasing power flows.

The FES show a lot of intermittent renewable generation in the north, meaning the spread of boundary power flows is very wide. With low generation output in the north it is credible to have power flowing from south to north feeding northern demand. The magnitude of the south to north power flows is low compared to those in the opposite direction so network capability should be sufficient to support those conditions.

# Boundary B7a – Upper North of England

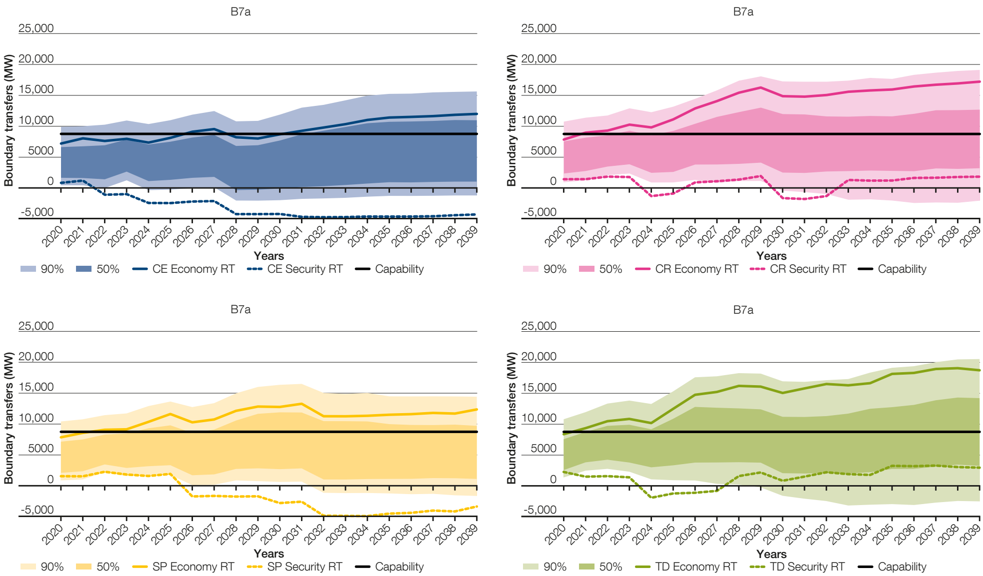
**Figure B7a.1**
Geographic representation of boundary B7a




B7a cuts across three 400kV double circuits and one 275kV circuit. The Western HVDC link also crosses the boundary.

Boundary B7a bisects England south of Teesside and into the Mersey Ring area. It is used to capture network restrictions on the circuits feeding down through Liverpool, Manchester and Leeds.

**Figure B7a.2**
Boundary flows and base capability for boundary B7a




## Boundary requirements and capability

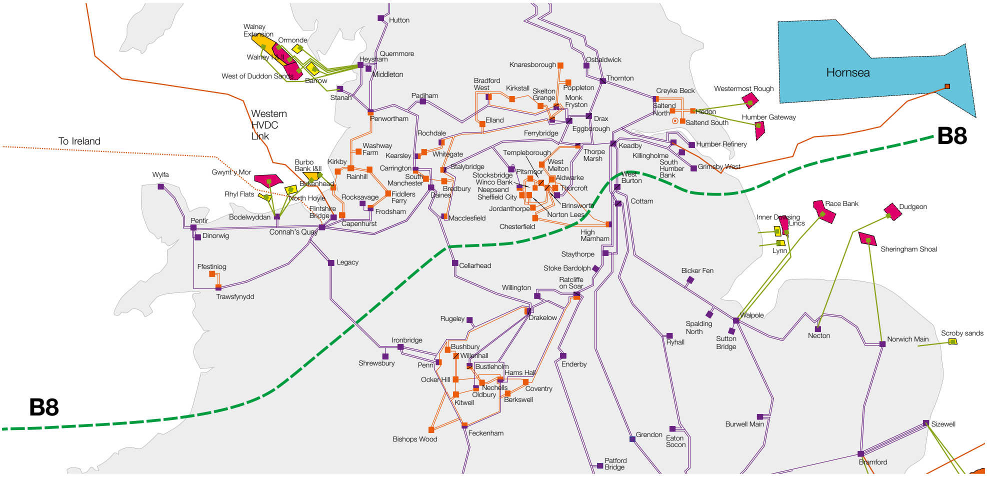
Figure B7a.2 above shows the projected boundary power flows crossing B7a for the next 20 years. The boundary capability has remained at 8.7 GW and is limited by the loading of the 400kV circuits from Penwortham.

For all except the **Consumer Evolution** scenario, the SQSS economy required transfer and expected power flows grow to well beyond the present boundary capability in the next ten years. This suggests a need for network development to manage the increasing power flows.

The FES, show a lot of intermittent renewable generation in the north, meaning the spread of boundary power flows is very wide. With low northern generation output, it is credible to have power flowing from south to north feeding northern demand. The magnitude of the south to north power flows is low compared to those in the opposite direction so network capability should be sufficient to support those conditions.

# Boundary B8 – North of England to Midlands

**Figure B8.1**
Geographic representation of boundary B8

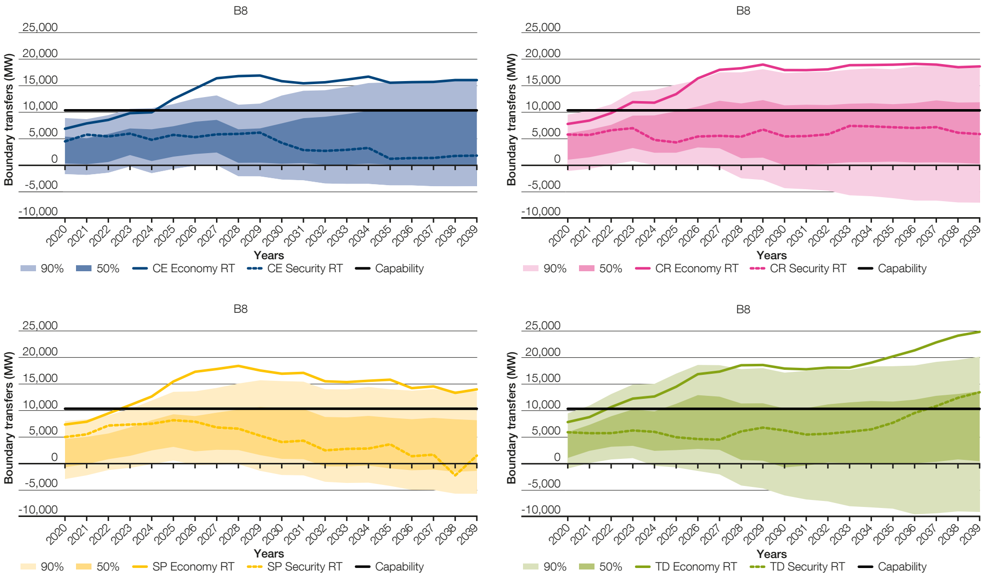



B8 cuts across four 400kV double circuits and a limited 275kV connection to South Yorkshire.

Boundary B8 is one of the wider boundaries that intersects the centre of GB, separating the northern generation zones including Scotland, Northern England and North Wales from the Midlands and southern demand centres.

## Figure B8.2

Boundary flows and base capability for boundary B8




## Boundary requirements and capability

Figure B8.2 above shows the projected boundary power flows crossing B8 for the next 20 years. The boundary capability is limited to 10.3GW due to loading limits of a Cellarhead–Drakelow 400kV circuit.

Across all four FES, the SQSS economy required transfer and expected power flows grow to beyond the present boundary capability. This suggests a need for network development to manage the increasing power flows.

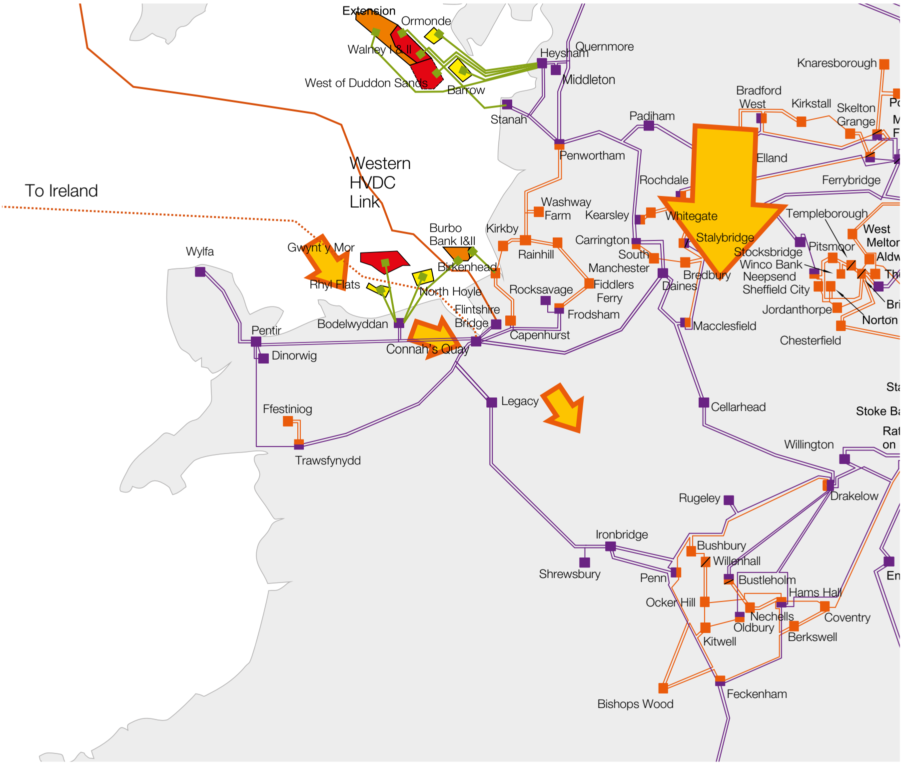
The FES, show a lot of intermittent renewable generation in the north, meaning the spread of boundary power flows is very wide. With low northern generation output, it is credible to have power flowing from south to north feeding northern demand, although this is not significant until beyond ten years in the future. The magnitude of the south to north power flows is low compared to those in the opposite direction so network capability should be sufficient to support those conditions.

# 3.6 Network capability and requirements by region – Wales and the Midlands boundaries

## Introduction

The Western transmission region includes boundaries in Wales and the Midlands. The figure below shows likely power flow directions in the years to come up to 2029. The arrows in the diagram are to illustrate power flow directions and, to an approximate scale, the flow magnitude in winter peak.

**Figure WM.1**
Wales and Midlands transmission network



## Primary challenge statement:

Future offshore wind and biomass generation connecting in North Wales have the potential to drive increased power flows eastward into the Midlands where power plant closures are set to occur and demand is set to remain fairly high.

## Regional drivers

By 2035, the scenarios suggest a total amount of generation capacity of between 11 GW to 19 GW, which is a reduction from present capacity of 24 GW (see figure WM.2). At present, this region has significant levels of fossil fuel (about 20 GW). All scenarios show a decline in fossil fuel with slight growth in low-carbon technologies, interconnectors and storage.

## Figure WM.2

Generation capacity mix scenarios for Wales and the Midlands

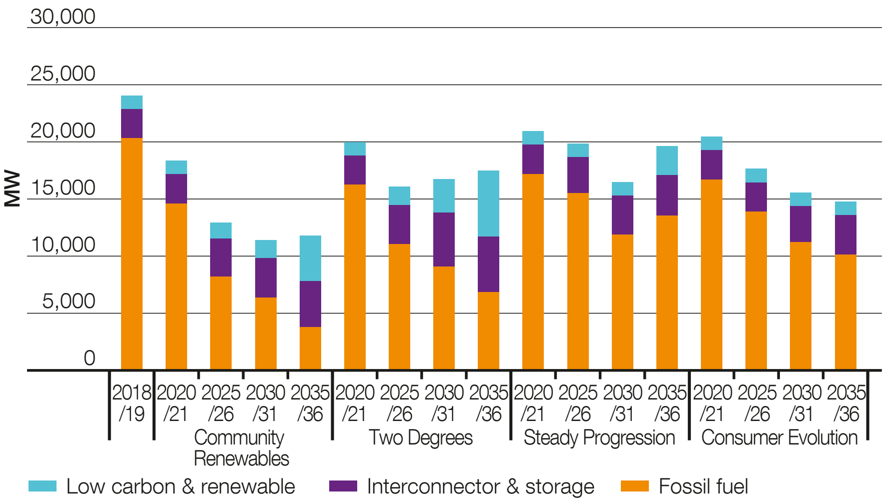
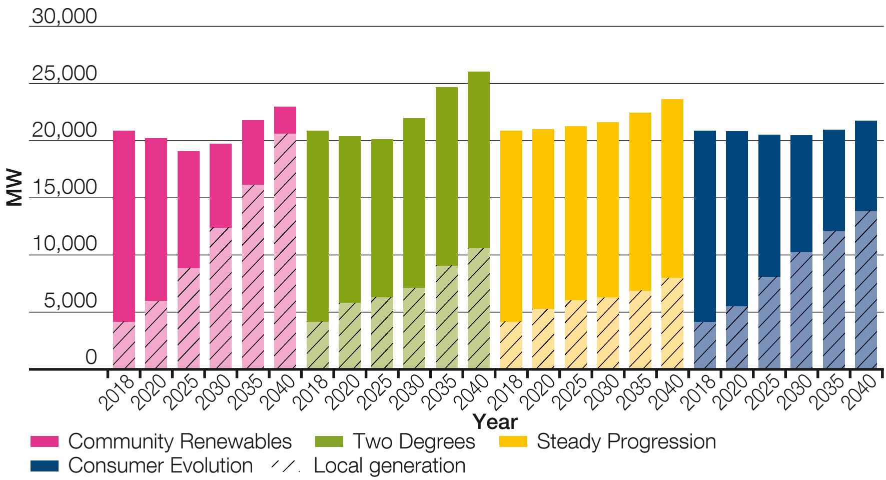



Figure WM.3 shows that the gross demand as seen from the transmission network in the region will increase across all scenarios. This is driven by the adoption of technologies such as electric vehicles, heat pumps and embedded storage. In a high decentralised scenario like **Community Renewables**, local generation capacity connected at the distribution level in this western region could reach more than 49 GW by 2040. Of that capacity, a typical embedded generation output on average might be around 20 GW. This will vary depending on factors like wind speeds, and how other local generators decide to participate in the market.

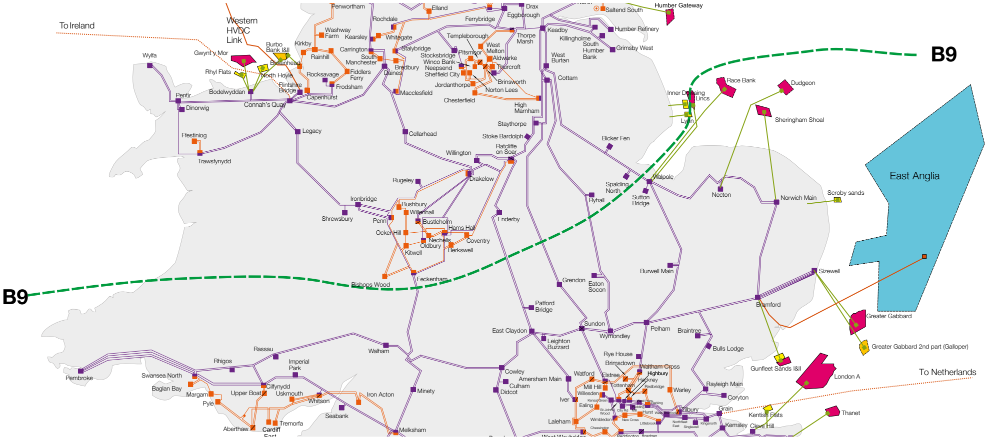
**Figure WM.3**
Gross demand scenarios for Wales and the Midlands




The transmission network in North Wales consists of only nine 400kV double circuits. Recent changes in generation background have reduced requirements in boundaries NW1, NW2, NW3 and B9.

# Boundary B9 – Midlands to South of England

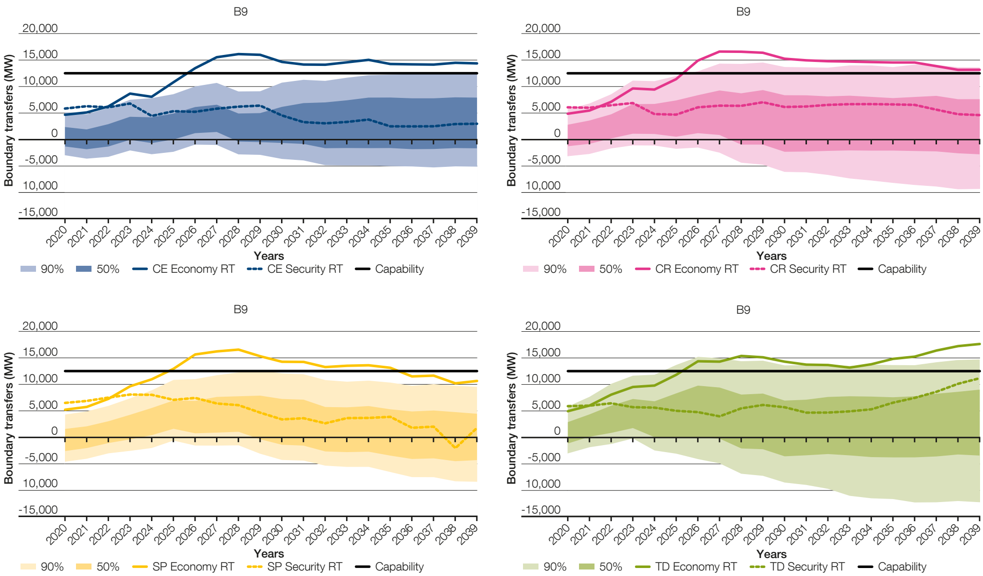
**Figure B9.1**
Geographic representation of boundary B9




## B9 cuts across five major 400kV double circuits transporting power over a long distance.

Boundary B9 separates the northern generation zones and the southern demand centres. Developments in the east coast and the East Anglia regions, such as the locations of offshore wind generation connection and the network infrastructure requirements, will affect the transfer requirements and capability of boundary B9.

## Figure B9.2
Boundary flows and base capability for boundary B9




## Boundary requirements and capability

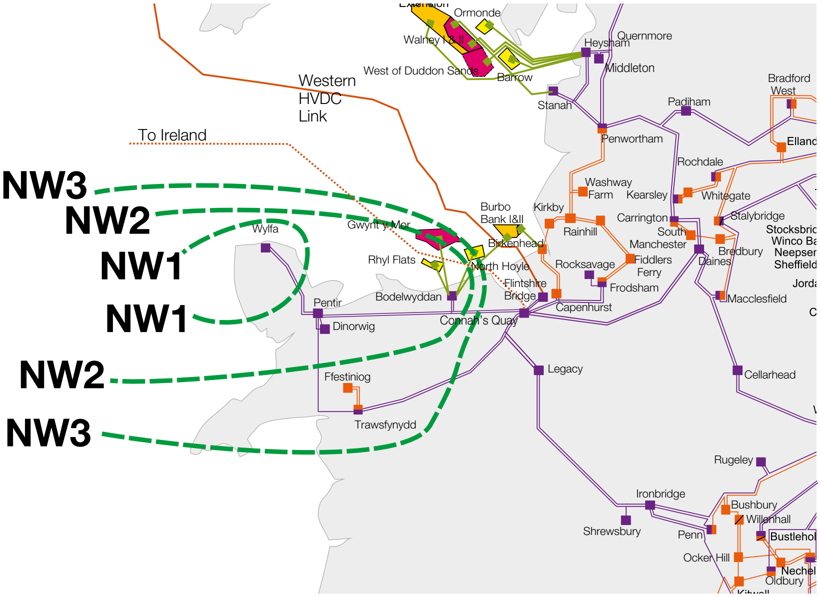
Figure B9.2 above shows the projected boundary power flows crossing B9 for the next 20 years. The boundary capability is voltage limited at 12.5 GW for a fault on the Enderby–Ratcliffe on Soar double-circuit.

Across all four FES, the SQSS economy required transfer grows beyond the present boundary capability. However, the expected power flows do not exceed the existing capability in **Steady Progession** and **Consumer Evolution** and only marginally exceed it in **Community Renewables** and **Two Degrees** scenarios. It is unlikely to drive any network development for B9.

# North Wales – overview

The onshore network in North Wales comprises a 400kV circuit ring that connects Pentir, Connah's Quay and Trawsfynydd substations. A 400kV double-circuit spur crossing the Menai Strait and running the length of Anglesey connects the now decommissioned nuclear power station at Wylfa to Pentir. A short 400kV double-circuit cable spur from Pentir connects Dinorwig pumped storage power station. In addition, a 275kV spur traverses north of Trawsfynydd to Ffestiniog pumped storage power station. Most of these circuits are of double-circuit tower construction. However, Pentir and Trawsfynydd within the Snowdonia National Park are connected by a single 400kV circuit, which is the main limiting factor for capacity in this area. The area is studied by analysing the local boundaries NW (North Wales) 1 to 3.

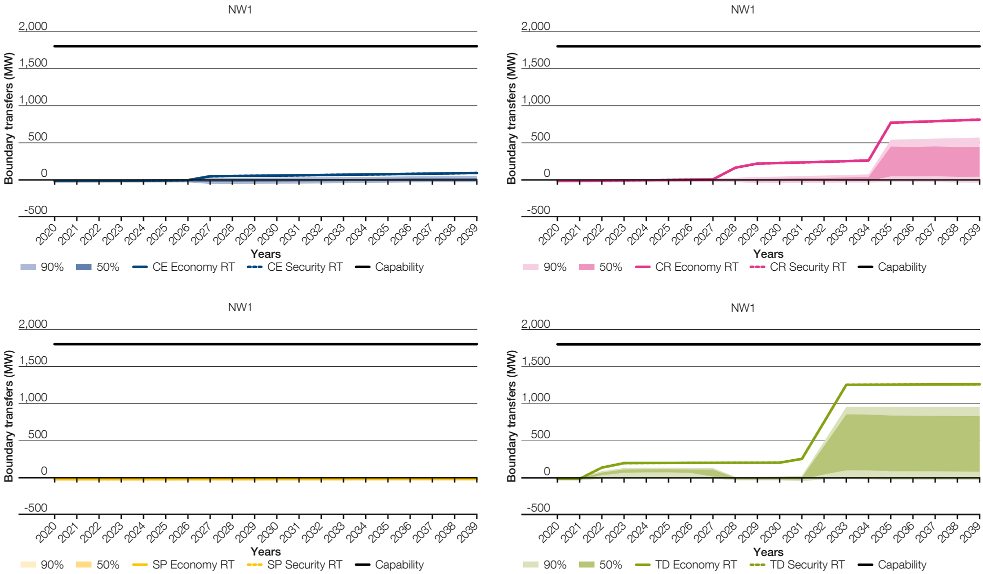
**Figure NW**
Geographic representation of North Wales boundaries




- NW1 is a local boundary crossing a 400kV double circuit.
- NW2 is a local boundary crossing a 400kV double circuit and a 400kV single circuit.
- NW3 a local boundary crossing a pair of 400kV double circuits.

# Boundary NW1 – Anglesey

## Figure NW1
Boundary flows and base capability for boundary NW1




## Boundary requirements and capability

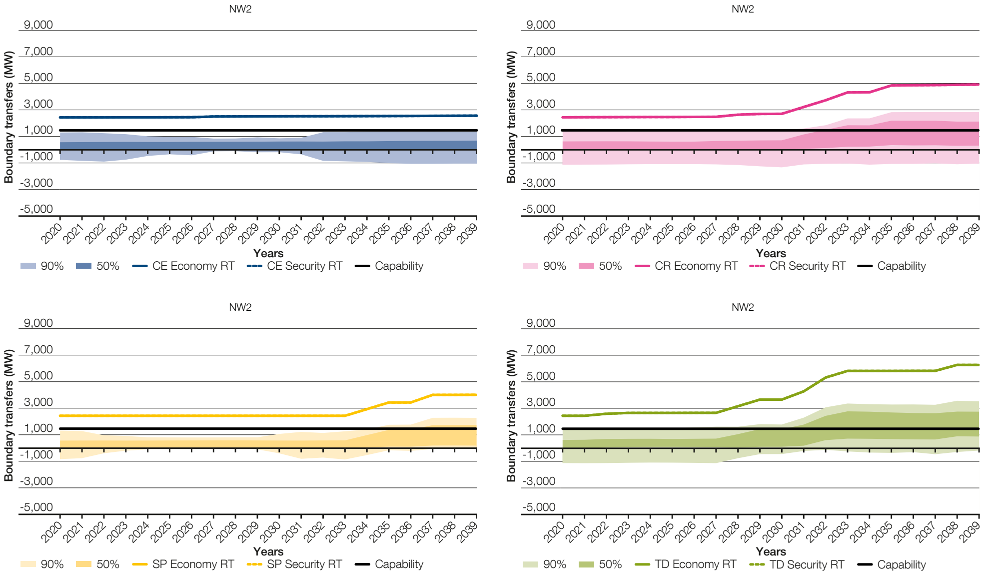
Figure NW1 above shows the projected boundary power flows crossing NW1 for the next 20 years. The boundary transfer capability is limited by the infrequent infeed loss risk criterion set in the SQSS, which is currently 1,800 MW. If the infrequent infeed loss risk is exceeded, the boundary would need to be reinforced by adding a new transmission route across the boundary.

Across all four scenarios, the SQSS economy required transfer and expected power flows remain below the present boundary capability. The generation expected behind NW1 is a combination of offshore wind generation and biomass generation.

# Boundary NW2 – Anglesey and Caernarvonshire

## Figure NW2

Boundary flows and base capability for boundary NW2




### Boundary requirements and capability

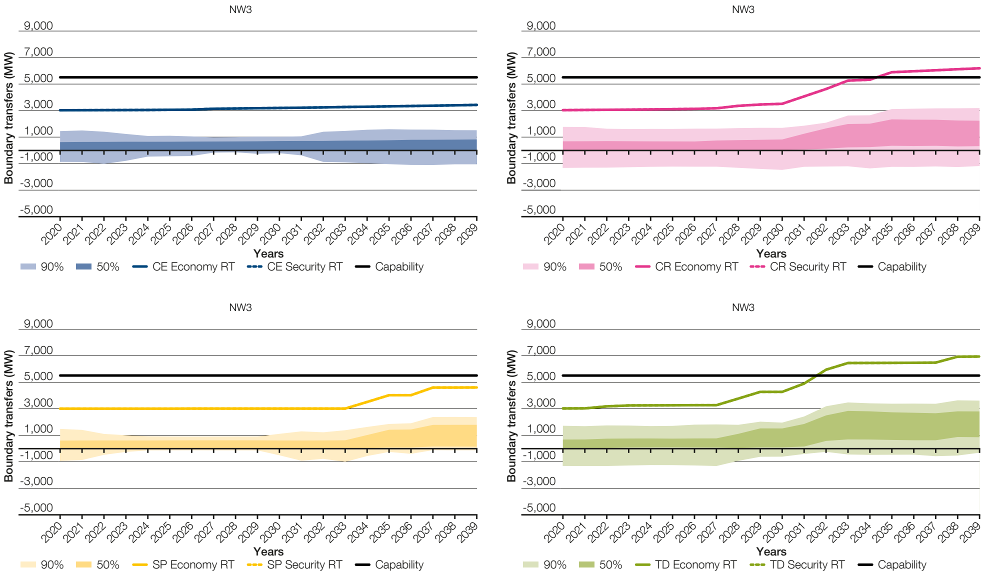
Figure NW2 above shows the projected boundary power flows crossing NW2 for the next 20 years. The boundary capability is thermally limited at 1.4 GW for a double-circuit fault on the Connah's Quay–Bodelwyddan–Pentir circuits which overloads the Pentir–Trawsfynydd single circuit.

Across all four FES, the SQSS economy required transfer grows beyond the present boundary capability. The expected power flows only grow beyond present capability from around 2029. The scenarios show similar requirements until 2027 where they diverge due to different assumptions of connection time and dispatching of potential offshore wind and biomass generation behind this boundary.

# Boundary NW3 – Anglesey and Caernarvonshire and Merionethshire

## Figure NW3

Boundary flows and base capability for boundary NW3




## Boundary requirements and capability

Figure NW3 above shows the projected boundary power flows crossing NW3 for the next 20 years. The boundary capability is thermally limited at 5.5 GW for a double-circuit fault on the Trawsfynydd–Treuddyn–Connah's Quay tee circuits which overloads the Connah's Quay–Bodelwyddan–Pentir tee circuits.

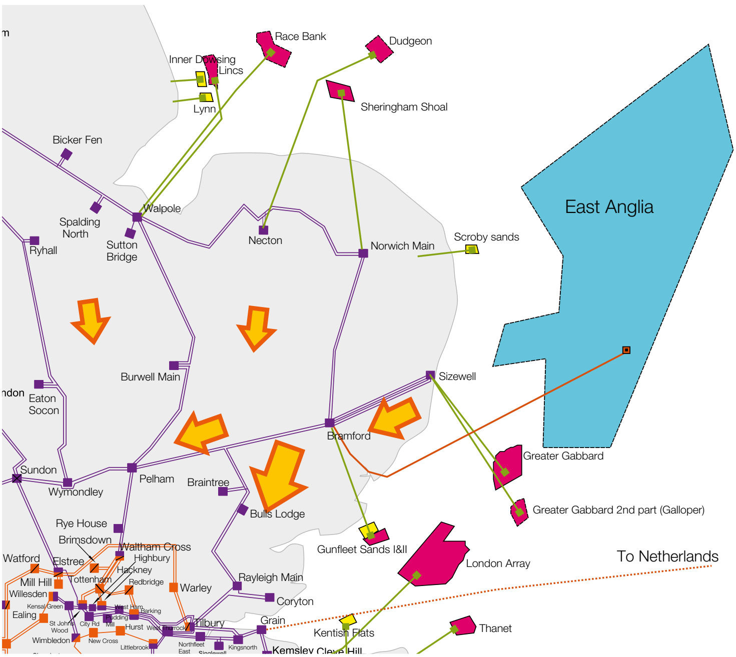
Only in the **Consumer Renewables** and **Two Degrees** scenarios do we see the SQSS economy required transfer and expected power flows grow beyond the present boundary capability. The scenarios show a similar requirement until 2027 where they diverge due to different assumptions of connection time and dispatching of potential offshore wind and biomass generation behind this boundary.

# 3.7 Network capability and requirements by region – The East of England boundaries

## Introduction

The East of England region includes the counties of Norfolk and Suffolk. The figure below shows likely power flow directions in the years to come up to 2029. The arrows in the diagram are meant to illustrate power flow directions and an approximate scale to the flow magnitude in winter peak.

**Figure EE.1**
East of England transmission network



## Primary challenge statement:

With the large amount of generation contracted to be connected in the area, predominantly offshore wind, nuclear and interconnector developments, the supply may significantly exceed the local demand which could cause heavy circuit loading, voltage depressions and stability issues.

## Regional drivers

The future energy scenarios highlight that generation between 7 and 27 GW could be expected to connect within this region by 2035 as shown in figure EE.2. All scenarios show that, in the years to come, large amounts of low-carbon generation, predominantly wind, can be expected to connect. Fossil fuel generation can also be expected to connect within this region as well as an interconnector. The total generation in all the scenarios will exceed the local demand; thus the East of England will be a power exporting region.

**Figure EE.2**
Generation capacity mix scenarios for the East of England

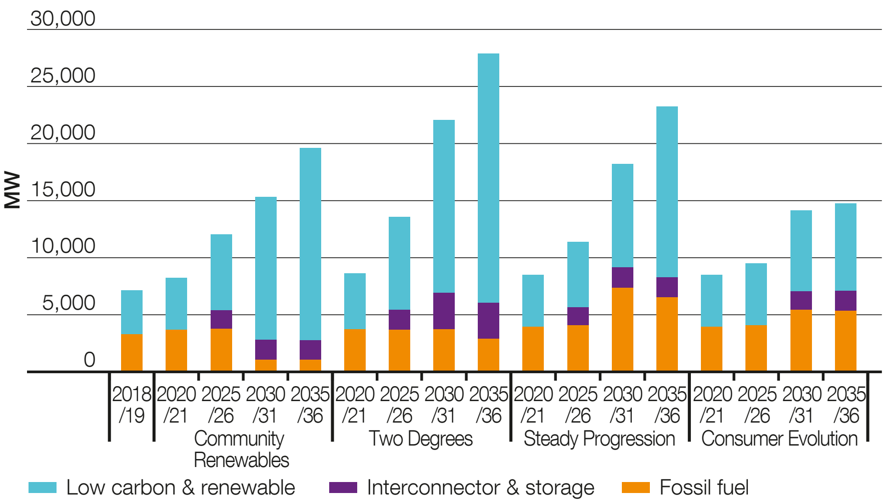
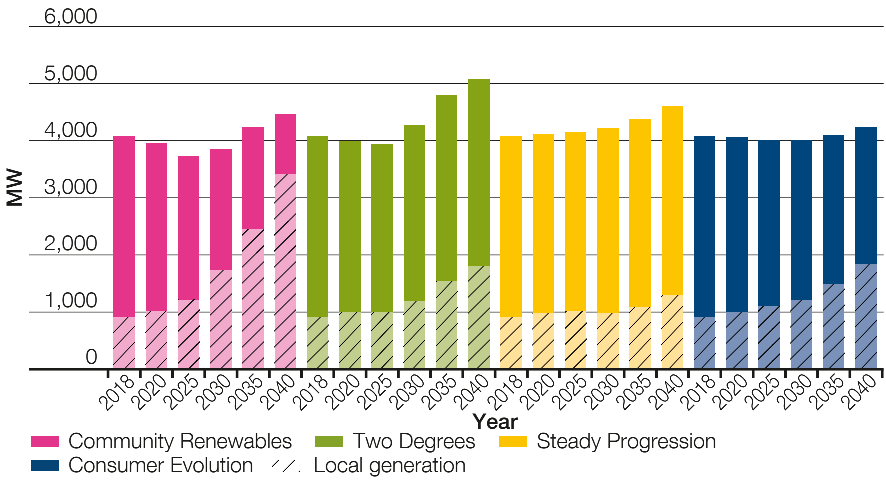


**Figure EE.3**
Gross demand scenarios for the East of England




Peak gross demand in the East of England region is expected to be around 5 GW by 2040. Figure EE.3 shows snapshots of the peak gross demand for the East of England across the four different scenarios. In a highly decentralised scenario like **Community Renewables**, local generation capacity connected at the distribution level in this eastern region could reach more than 12 GW by 2040. Of that capacity, a typical embedded generation output on average might be around 3.4 GW. This will vary depending on factors like wind speeds, and how other local generators decide to participate in the market.

The East Anglia transmission network to which the future energy scenarios, generation will connect has eight 400kV double circuits. The potential future increase in generation within this region could force the network to experience very heavy circuit loading, stability issues and voltage depressions – for power transfer scenarios from East Anglia to London and south east England. This is explained as follows:

- The East of England region is connected by several sets of long 400kV double circuits, including Bramford Pelham/Braintree, Walpole–Spalding North/Bicker Fenn and Walpole–Burwell Main.

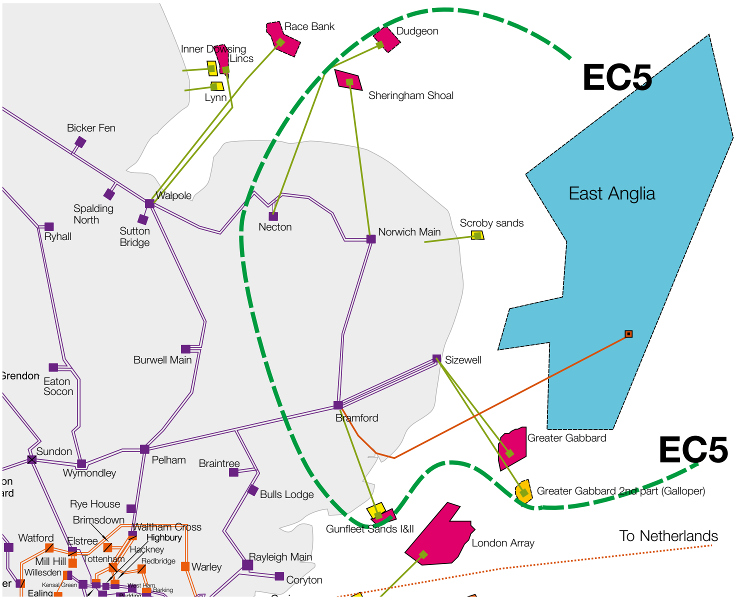
During a fault on any one set of these circuits, power exported from this region is forced to reroute. This causes some of the power to flow through a much longer distance to reach the rest of the system, predominantly the Greater London and south east England networks via the East Anglia region. As a result, the reactive power losses in these high impedance routes increases. If these losses are not compensated they will eventually lead to voltage depressions within the region.

- Stability becomes an additional concern when some of the large generators connect, further increasing the size of the generation group in the area connected to the network. Losing a set of double circuits when a fault occurs will lead to significant increases in the impedance of the connection between this large generation group and the remainder of the system. As a result, the system may be exposed to a risk of instability as power transfer increases.

The *NOA 2019/20* will assess the likelihood and impact of the above mentioned potential scenarios and accordingly recommend preferred reinforcements for the East of England transmission region.

# Boundary EC5 – East Anglia

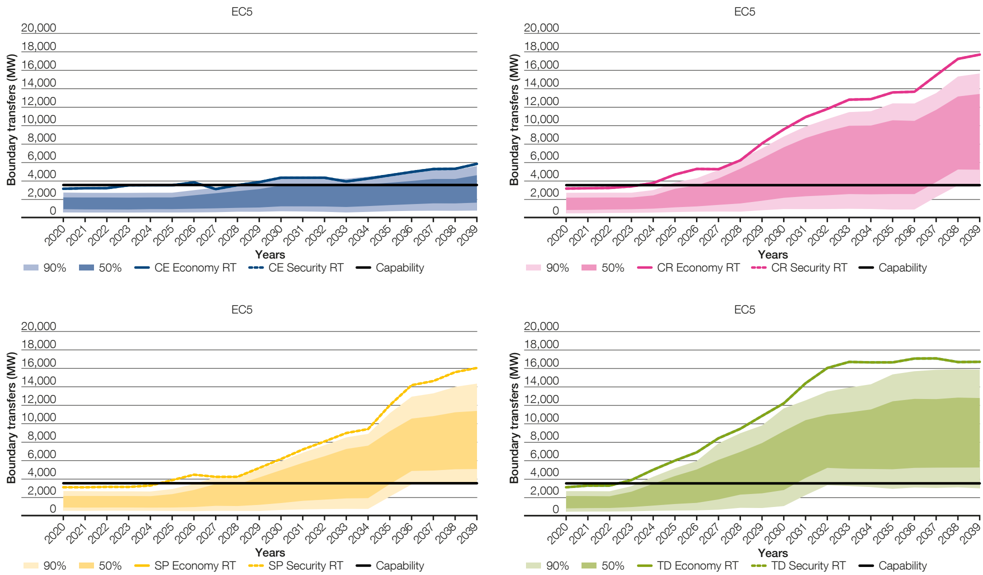
**Figure EC5.1**
Geographic representation of boundary EC5




EC5 – a local boundary encloses four 400kV substations and cuts across four 400kV circuits.

Boundary EC5 is a local boundary enclosing most of East Anglia. The coastline and waters around East Anglia are attractive for the connection of offshore wind projects, including the large East Anglia Round 3 offshore zone that lies directly to the east. The existing nuclear generation site at Sizewell is one of the approved sites selected for new nuclear generation development. A new interconnector project will also connect within this boundary.

## Figure EC5.2
Boundary flows and base capability for boundary EC5




## Boundary requirements and capability

Figure EC5.2 above shows the projected boundary power flows for boundary EC5 for the next 20 years. The boundary capability is currently a voltage compliance limit at 3.5 GW for a double-circuit fault on the Bramford–Pelham and Bramford–Braintree–Rayleigh Main circuits causing low voltage at Burwell Main substation.

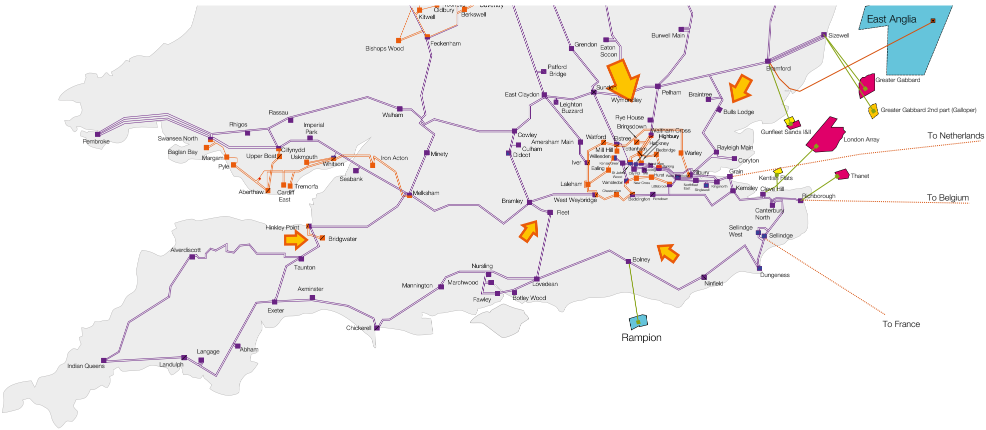
The growth in offshore wind, nuclear generation and interconnector capacities connecting behind this boundary greatly increase the power transfer requirements. The present boundary capability is sufficient for today's needs but could be significantly short of the future capability requirements. In all scenarios, except **Consumer Evolution**, the SQSS economy required transfer and expected power flows grow rapidly from around 2023 to beyond the present boundary capability. This suggests a need for network development to manage the increasing power flows.

# 3.8 Network capability and requirements by region – The South of England boundaries

## Introduction

The South of England transmission region includes boundaries B13, B14, LE1, SC1, SC2 and SC3. The region includes the high demand area of London, generation around the Thames estuary and the long set of circuits that run around the south coast. Interconnection to Central Europe is connected along the south east coast and this interconnection has significant influence on power flows in the region by being able to both import and export power with Europe. The figure below shows likely power flow directions in the years to come up to 2029. The arrows in the diagram are meant to give illustration to power flows and an approximate scale to the flow magnitude in winter peak when importing energy to the UK on the interconnectors.

**Figure SE.1**
South of England transmission network



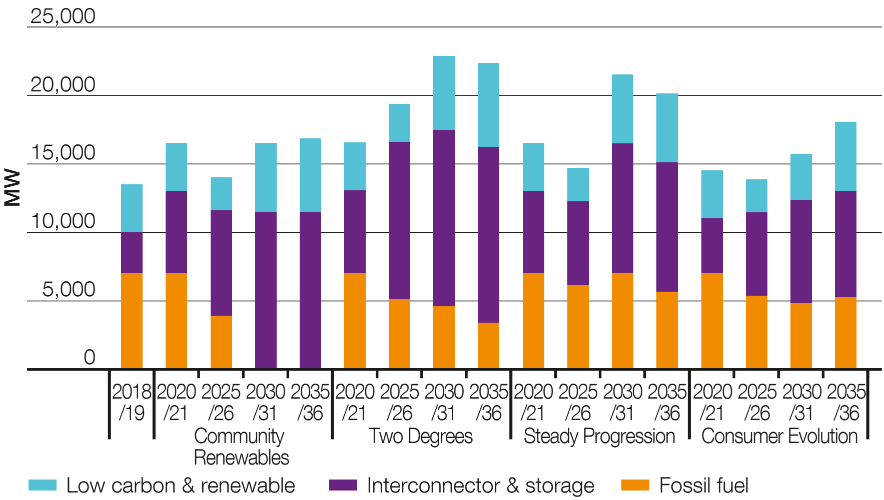
## Primary challenge statement:

European interconnector developments along the south coast could potentially drive very high circuit flows causing circuit overloads, voltage management and stability issues.

## Regional drivers

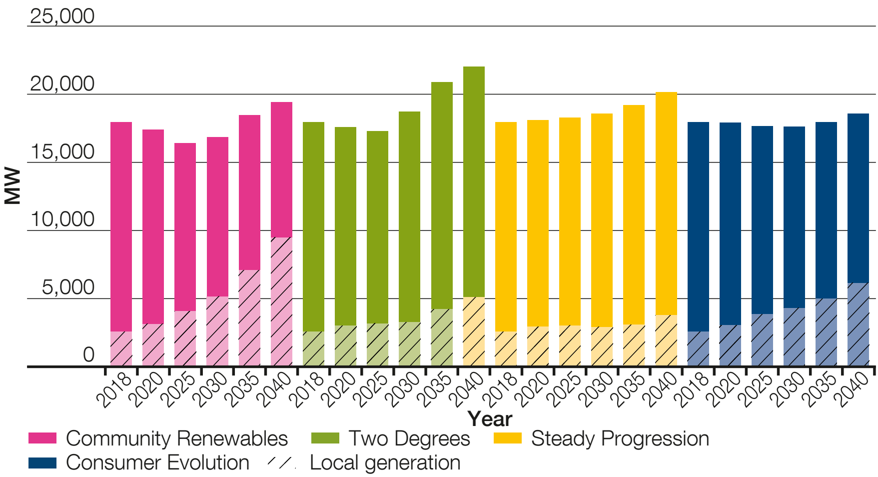
The **Two Degrees** scenario suggests that just over 12 GW of interconnectors and energy storage capacity may connect in the south as shown in figure SE.2. As interconnectors and storage are bi-directional, the south could see their capacity provide up to 12 GW power injection or 12 GW increased demand. This variation could place a very heavy burden on the transmission network. Most of the interconnectors will be connected south of boundary SC1 so the impact can be seen later in the chapter in the SC1 requirements.

**Figure SE.2**
Generation capacity mix scenarios for the South of England




Peak gross demand in the south, as seen by the transmission network, is not expected to change significantly for most of the scenarios. By 2040, the expected peak demand is between 18 GW and 22 GW across all scenarios as shown in figure SE.3. In a highly decentralised scenario like **Community Renewables**, local generation capacity connected at the distribution level in this region could reach up to 27 GW by 2040. Of that capacity, a typical embedded generation output on average might be around 9.5 GW. This will vary depending on factors like wind speeds, and how other local generators decide to participate in the market and capacity available on the distribution networks.

**Figure SE.3**
Gross demand scenarios for the South of England




The transmission network in the south is heavily meshed in and around London B14 and the Thames estuary, but below there and towards the west the network becomes more radial with relatively long distances between substations.

In the future, the southern network could potentially see a number of issues driven by future connections. If the interconnectors export power to Europe at the same time that high demand power is drawn both into and through London then the northern circuits feeding London will be thermally overloaded. The high demand and power flows may also lead to voltage depression in London and the south-east. The closure of conventional generation within the region will present added stability and voltage depression concerns which may need to be solved through reinforcements.

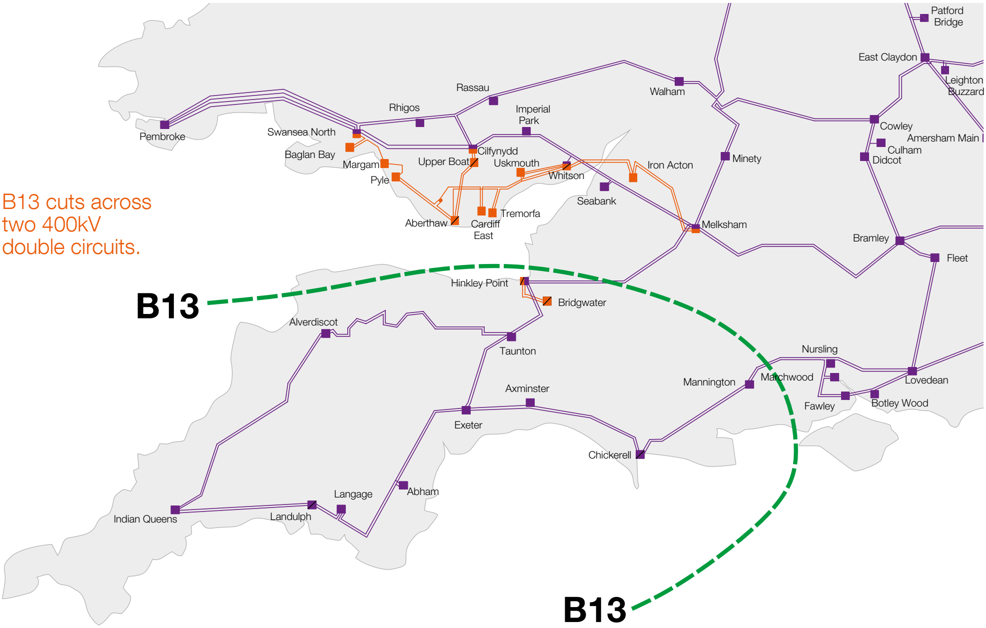
If the south-east interconnectors are importing from the Continent and there is a double-circuit fault south of Kemsley, then the south–east circuits may overload and there could be significant voltage depression along the circuits to Lovedean.

With future additional interconnector connections, the south region will potentially be unable to support all interconnectors importing or exporting simultaneously without network reinforcement. Overloading can be expected on many of the southern circuits. The connection of the new nuclear generating units at Hinkley may also require reinforcing the areas surrounding Hinkley. With new interconnector and generation connections, boundaries SC1, SC2, SC3, LE1 and B13 will need to be able to support large power flows in both directions which is different from today when power flow is predominantly in one direction.

The *NOA 2019/20* will assess the likelihood and impact of the above mentioned potential scenarios and accordingly recommend preferred reinforcements for the South of England transmission region.

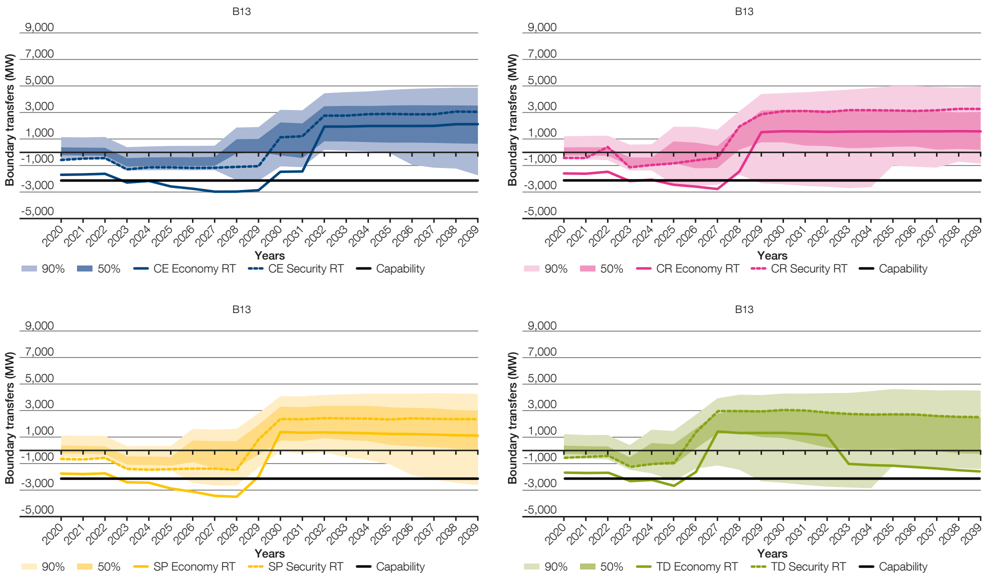
# Boundary B13 – South West

**Figure B13.1**
Geographic representation of boundary B13




Wider boundary B13 is defined as the southernmost tip of the UK below the Severn Estuary, encompassing Hinkley Point in the south west and stretching as far east as Mannington. The southwest peninsula is a region with a high level of localised generation and demand.

**Figure B13.2**
Boundary flows and base capability for boundary B13



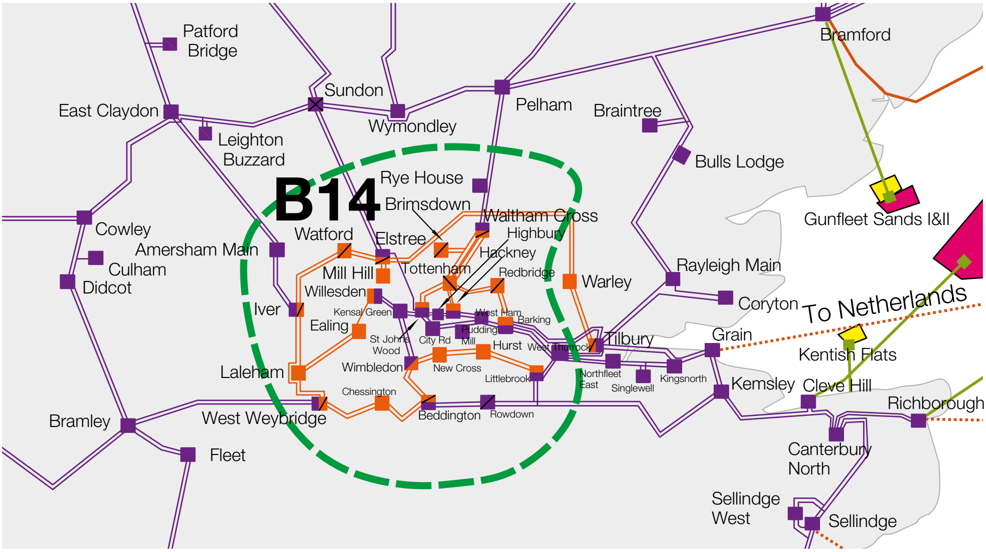

## Boundary requirements and capability

Figure B13.2 above shows the projected boundary power flows for boundary B13 for the next 20 years. The boundary capability is currently a voltage compliance limit at 2.1 GW for a double-circuit fault on Alverdiscott–Taunton circuits causing low voltage at Indian Queens substation.

It can be seen that until new generation or interconnectors connect there is very little variation in boundary requirements, and that the current importing boundary capability is sufficient to meet the short-term needs. The large size of the potential new generators wishing to connect close to boundary B13 is likely to push it to large exports and require additional boundary capacity.

# Boundary B14 – London

**Figure B14.1**
Geographic representation of boundary B14

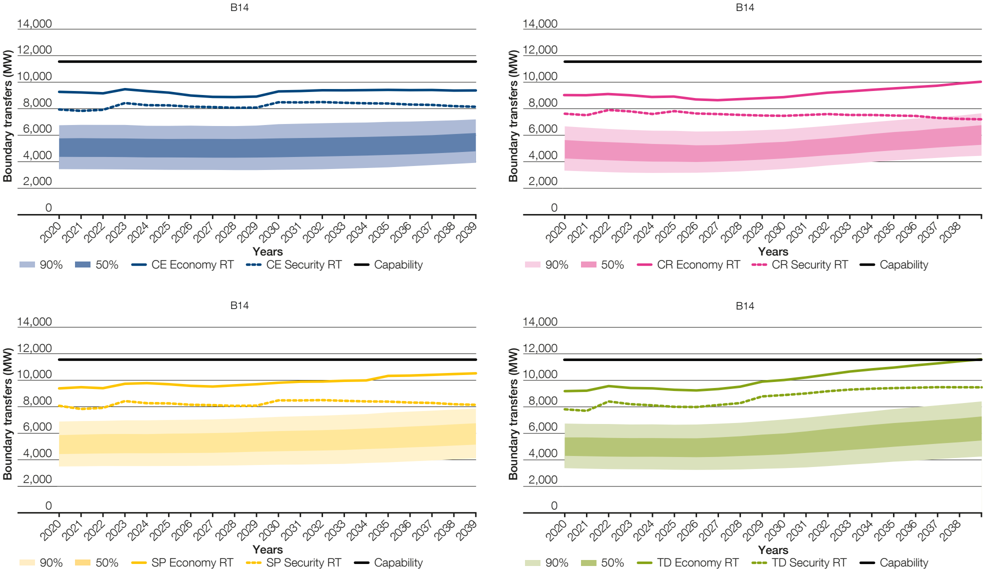



B14 cuts across eight 400kV double circuits and a 275kV double circuit.

Boundary B14 encloses London and is characterised by high local demand and a small amount of generation. London's energy import relies heavily on surrounding 400kV and 275kV circuits. The circuits entering from the north can be particularly heavily loaded at winter peak conditions. The circuits are further overloaded when the European interconnectors export to mainland Europe as power is transported via London to feed the interconnectors along the south coast.

## Figure B14.2

Boundary flows and base capability for boundary B14




## Boundary requirements and capability

Figure B14.2 above shows the projected boundary power flows for boundary B14 for the next 20 years across the four FES scenarios. The boundary capability is currently limited by thermal constraints at 11.6 GW for a double-circuit fault on the Grain–Kingsnorth and Grain–Tilbury circuits.

As the transfer across this boundary is mostly dictated to the contained demand, the scenario requirements mostly follow the demand with little deviation due to generation changes. The boundary requirements are close to each other across all four scenarios for security and economy required transfer. In both criteria, the required transfer is above 90 per cent flows, meaning planning for these values covers all possible flows.

# Boundary SC1 – South Coast

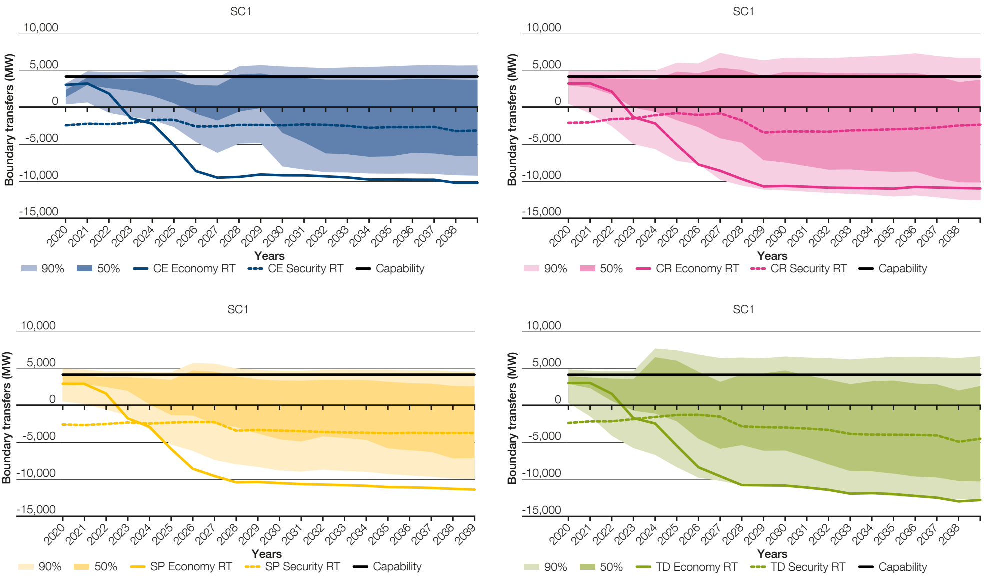
**Figure SC1.1**
Geographic representation of boundary SC1


Boundary SC1 runs parallel with the south coast between the Severn and Thames estuaries. At times of peak winter GB demand, the power flow is typically north to south across the boundary, with more demand enclosed in the south of the boundary than supporting generation.

Interconnector activity can significantly influence the boundary power flow. The current interconnectors to France, the Netherlands and Belgium connect at Sellindge, Grain and Richborough respectively.

## Figure SC1.2

Boundary flows and base capability for boundary SC1




## Boundary requirements and capability

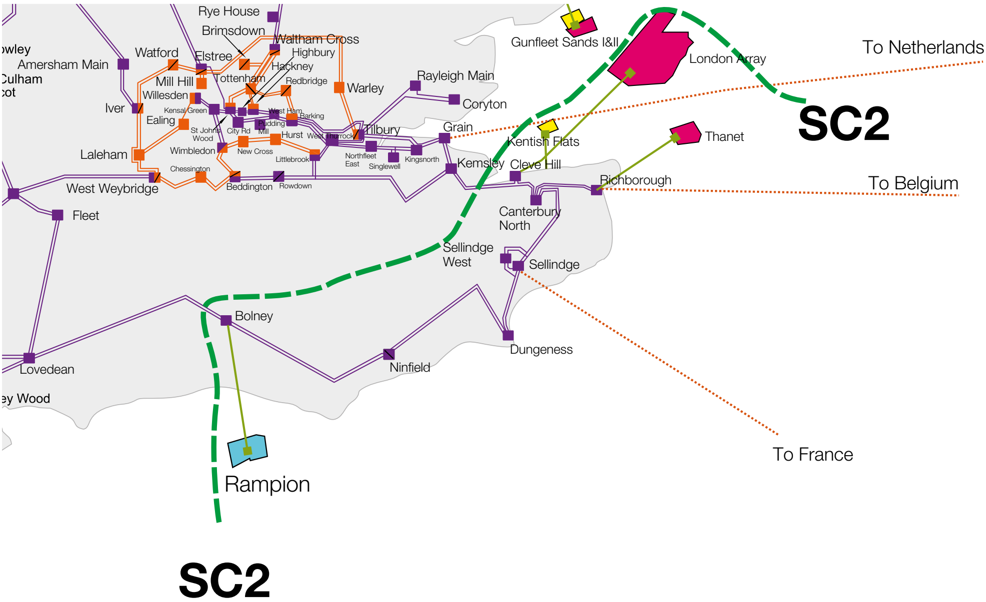
Figure SC1.2 shows the projected boundary power flows for boundary SC1 for the next 20 years across the four FES scenarios. Positive values represent power flow across the boundary from north to south. The boundary capability is currently limited by voltage compliance at 4.1 GW for a double-circuit fault on the Kemsley–Clevehill and Kemsley–Canterbury circuits for interconnector import sensitivity. For the interconnector export sensitivity, the limit is voltage collapse at 6.0 GW of transfer. This happens after Bramley–Fleet double-circuit contingency.

The interconnectors to Europe have a significant impact on the power transfers across SC1. A 2 GW interconnector such as IFA can make 4 GW of difference on the boundary from full export to full import mode or vice versa. The biggest potential driver for SC1 will be the connection of new Continental interconnectors. With their ability to transfer power in both directions, boundary SC1 could be overloaded much more than normal with conventional generation and demand.

Across all four FES, the SQSS security required transfer follows a generally flat pattern, whereas the economy required transfer moves from exporting to importing in around 2023. The volatility of interconnector activity can be seen in the required transfers as the requirements swing from power flow south and north. The SQSS calculation of required transfers does not place high loading on the interconnectors so the transfers are not seen to peak at very high values.

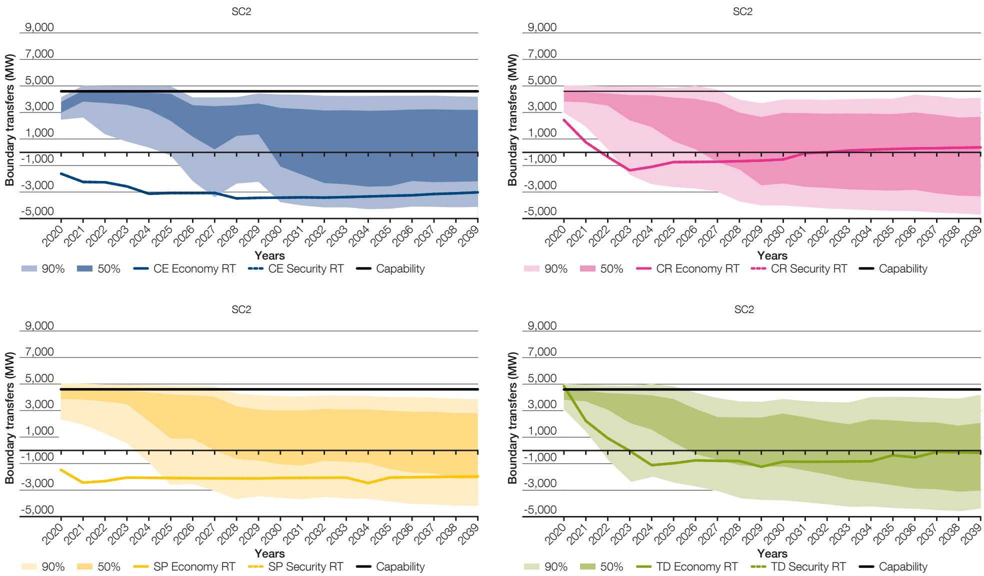
# Boundary SC2 – South Coast

**Figure SC2.1**
Geographic representation of boundary SC2




Boundary SC2 is a subset of the SC1 boundary created to capture transmission issues specifically in the south part of the network between Kemsley and Lovedean. The relatively long 400kV route between Kemsley and Lovedean feeds significant demand and connects both large generators and interconnection to Europe. A fault at either end of the route can cause it to become a long radial feeder which puts all loading on the remaining two circuits which can be restrictive due to circuit ratings and cause voltage issues. Additional generation and interconnectors are contracted for connection below SC2 which can place additional burden on the region.

## Figure SC2.2
Boundary flows and base capability for boundary SC2

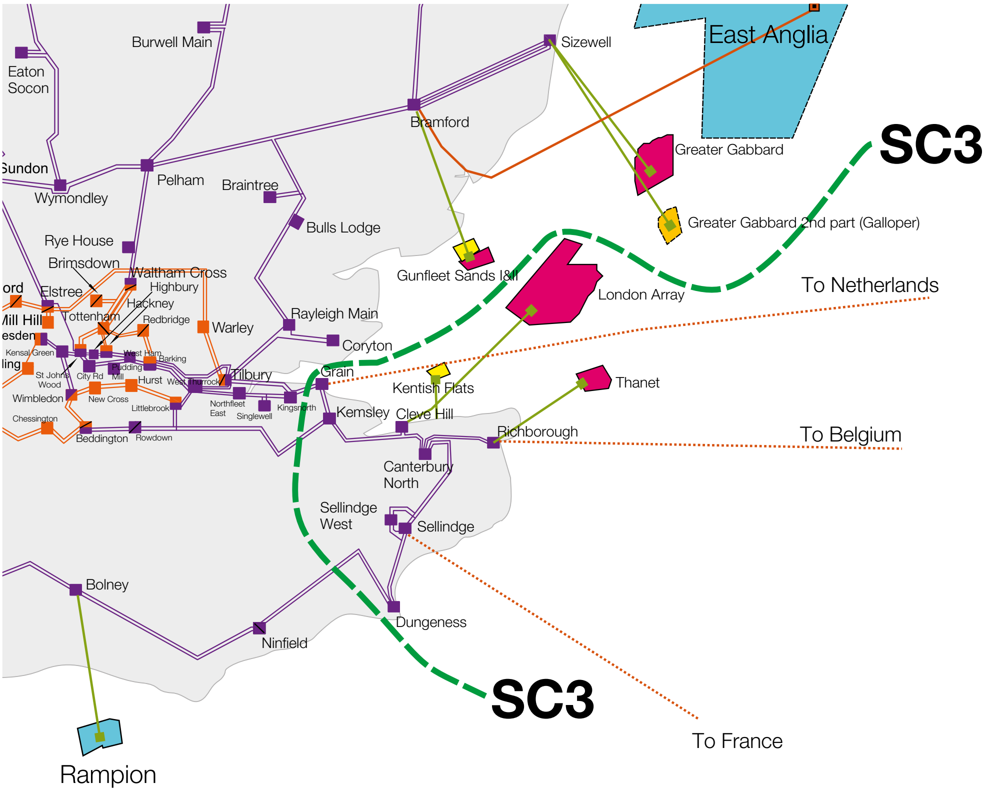



## Boundary requirements and capability

Figure SC2.2 above shows the required transfers and expected power flows for boundary SC2. Positive values represent exporting power flows out of the south east area enclosed by the boundary. The boundary capability is currently voltage stability limited at 4.6 GW. The interconnectors with Europe have a large impact on the power transfers across SC2 as a 2.0 GW interconnector can make 4.0 GW of difference on the boundary if it moves from import to export. The volatility of interconnector activity can be seen in the wide spread of expected boundary flows depicted by the central darker band in figure SC2.2.

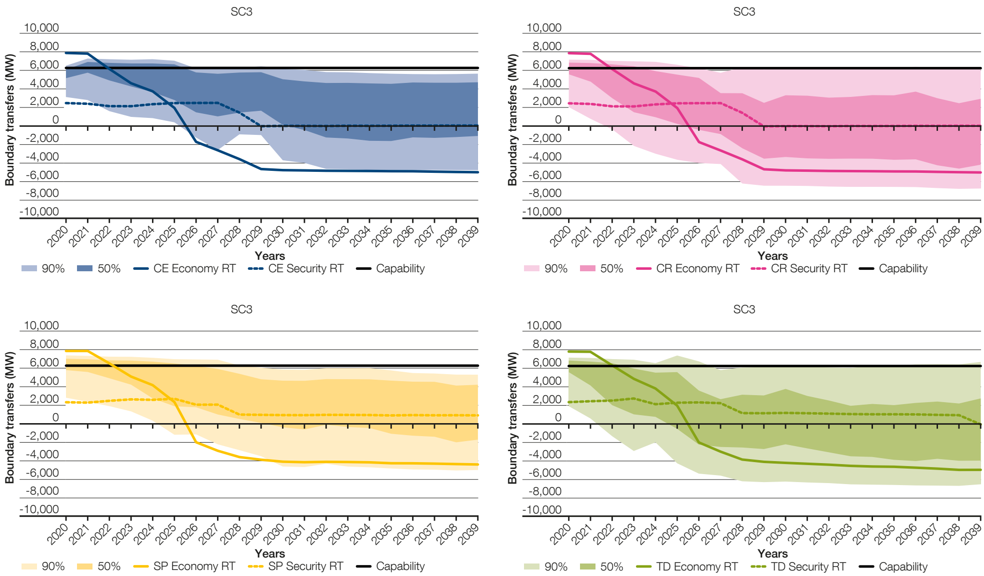
# Boundary SC3 – South Coast

**Figure SC3.1**
Geographic representation of boundary SC3




Boundary SC3 is created to capture transmission issues specifically in the south-east part of the network. The current and future interconnectors to Europe have a significant impact on the power transfers across SC3. The current interconnectors to France, the Netherlands and Belgium connect at Sellindge, Grain and Richborough respectively.

## Figure SC3.2
Boundary flows and base capability for boundary SC3




## Boundary requirements and capability

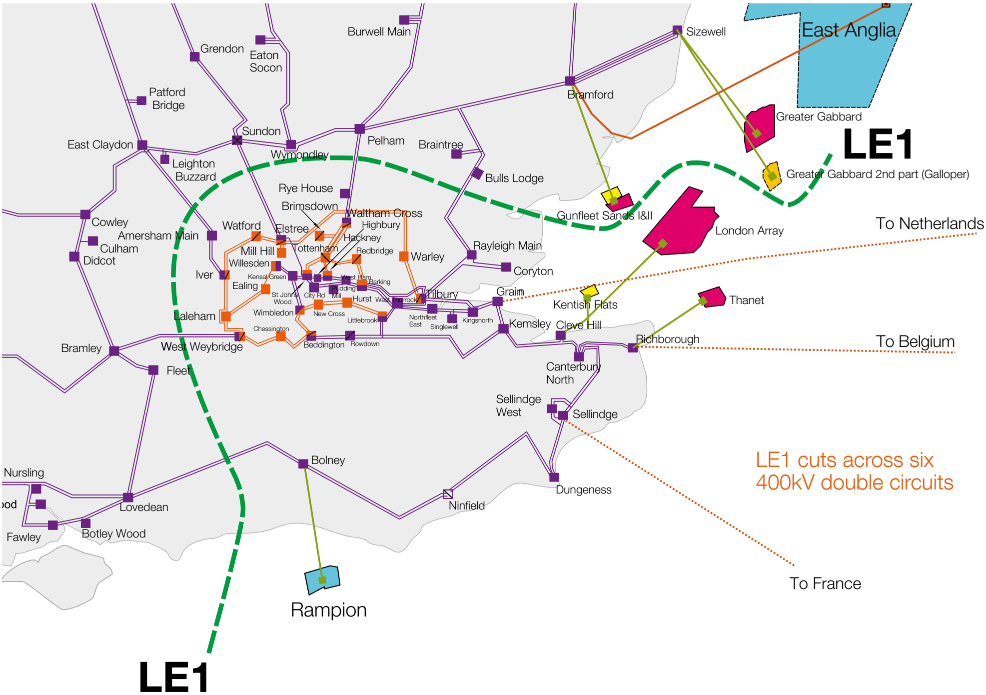
Figure SC3.2 shows the projected boundary power flows for boundary SC3 for the next 20 years across the four FES scenarios. Positive values represent power flow across the boundary from north to south. The boundary capability is currently limited by thermal loading at 6.2 GW for a double-circuit fault on the Grain–Tilbury–Kingsnorth circuits.

The current and future interconnectors to Europe have a significant impact on the power transfers across SC3 with their ability to transfer power in both directions.

Across all four FES scenarios, the SQSS security required transfer follows similar patterns and is mainly lower compared to the economy required transfer. In general, the economy required transfer faces a decline over the time, albeit it does not reflect the interconnectors uncertainties. The uncertainty of interconnector activity can be seen in the wide spread of the boundary flows depicted by the central darker band in figure SC3.2.

# Boundary LE1 – South East

**Figure LE1.1**
Geographic representation of boundary LE1

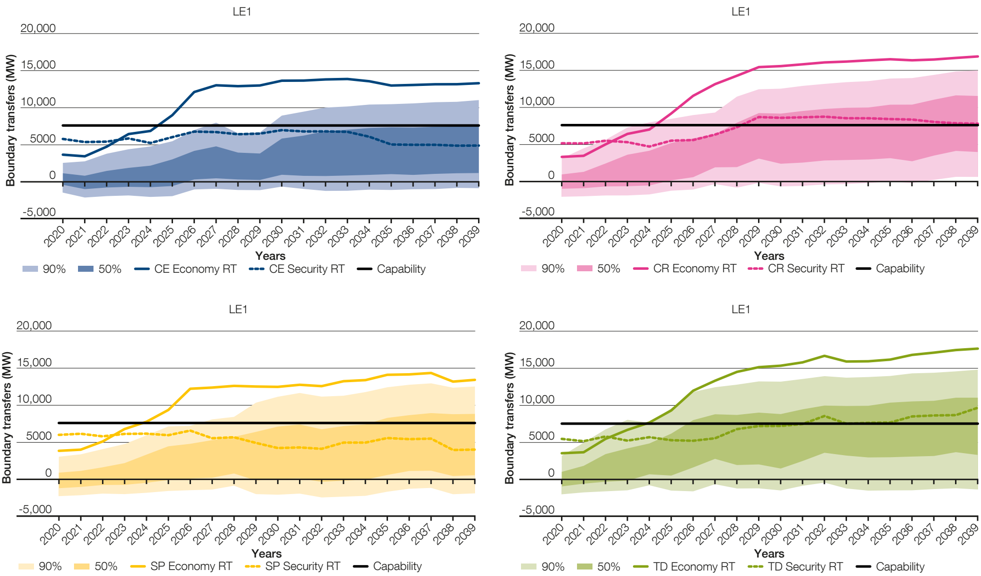



Boundary LE1 encompasses the south east of the UK, incorporating London and the areas to the south and east of it. LE1 is characterised by two distinct areas. Within London, there is high local demand and little generation. The remainder of the area contains both high demand and high levels of generation. In particular, there are a number of gas power generators in the Thames estuary area and an interconnector to the Netherlands, while connected to the south east coast are a number of wind farms, interconnectors to France and Belgium, as well as nuclear and gas power stations.

LE1 almost exclusively imports power from the north and west into the south east, and the purpose of the boundary is to monitor flows in this direction. With the existing and proposed interconnectors importing power from the Continent, power flows enter London from all directions, to the extent that flows across LE1 reduce and limited constraints are seen similar to those shown by B14 on the south coast boundaries. However, with increased number of interconnectors, and (in some scenarios) increased likelihood of them exporting power in future years, LE1 can become a high demand area, with any locally generated power feeding straight into the interconnectors. As such, the circuits entering LE1 from the north can become overloaded as power is drawn into and through London toward the south and east.

## Figure LE1.2

Boundary flows and base capability for boundary LE1




## Boundary requirements and capability

Figure LE1.2 shows the projected boundary power flows for boundary LE1 for the next 20 years across the four FES scenarios. The boundary capability is currently limited by thermal constraints at 7.6 GW with overloads of the Rayleigh Main–Tilbury circuit.

Across all four FES, the SQSS economy required transfer grows beyond existing boundary capability from 2023. Across all the scenarios, the expected power flows are less than the required transfer and the uncertainty of interconnector activity can be seen in the wide range of the boundary flows.

# 3.9 Regional high voltage pathfinder projects

## Introduction

Last year, we presented the challenges we face, as the ESO, managing system voltages, particularly within the upper limit. Over the last decade, the reliance on using balancing services for reactive power control has increased, and hence become more costly to manage. We presented a case for more proactive actions to be taken in planning timescale to better manage the situation. We shared our plans to address these challenges in the short term by voltage pathfinder projects and in the long term by establishing a new process within the *NOA*.

From the voltage pathfinder project, some regions were proposed which would potentially benefit from applying a regional approach and NOA-style assessment (Mersey and North England/Pennine). These projects have made progress over the last 12 months, and we'd like to share with you some of the latest developments.

### Mersey

We prioritised the Mersey region in the high voltage pathfinder project after our initial assessment. We're now progressing the tender stages for this project, having completed the following milestones over the last 12 months:

- Request for Information (RFI) published in March 2019.
- Webinar held in May 2019.
- RFI summary published and decision to tender confirmed in June 2019.
- Tender timescales published in September 2019.
- Tender to address short-term need published in October 2019.
- Tender to address long-term need published in November 2019.

We launched a tender in October for a reactive power service to meet a static need for the year starting April 2020. This tender enables embedded assets, for the first time, to participate in a tender to solve a transmission voltage system need. Then, in November, we followed with another tender for reactive power service need covering nine years, starting April 2022. This tender allows non-transmission network options, also for the first time, to compete directly with transmission network options to address a transmission voltage need.

### North England/Pennine

Through the RFI and tender for the Mersey region, we've received valuable feedback and queries from stakeholders. We've also learnt some important points while we developed the assessment methodology and commercial arrangements. We're mindful that while we should progress these pathfinders as quickly as possible, we need to be clear, transparent and provide a fair playing field to all parties (providers, TOs and DNOs) throughout the process. We are now working towards running a tender for Pennine region in Q1 2020/21. The exact timeline will be reviewed as we shall take learning from the Mersey tender and look to refine the approach for Pennine region.

If you'd like to find out more about our high voltage pathfinder project, please visit our Network Development Roadmap[4] page.

[4] https://www.nationalgrideso.com/publications/network-options-assessment-noa/network-development-roadmap

# Chapter 4
## Year-round probabilistic analysis

# 4.1 Introduction

**To improve how we address the possible impact of uncertain and wide ranging output from energy resources in the planning and operation of the NETS, it is necessary to analyse the full range of background conditions including the most likely and reasonable worst-case generation and demand background conditions.**

Early this year, we published a case study demonstrating the probabilistic approach on a single boundary SC3[1]. We have extended our probabilistic approach to assess several boundaries across the GB network. We have also explored different ways to present the results and how we can utilise these in our planning. We also highlight our tool development pathway.

[1]https://www.nationalgrideso.com/document/140781/download

# 4.2 Current approach and new requirements

## The year-round capability planning of the NETS has traditionally been carried out against deterministic generation and demand dispatch scenarios, agreed between the ESO and TOs in accordance with the SQSS planning standard.

The deterministic year-round approach has worked well so far because the generation mix has comprised relatively few intermittent technologies. In the future, however, generation will include a larger contribution of intermittent renewable sources and we will also see growing contribution from interconnectors whose behaviour is difficult to predict. We will also see more embedded generation of varied types. The SQSS states the need to consider network capability planning against generation, demand and network conditions that might reasonably arise during the course of the year. Therefore, using a probabilistic approach to look at a broader range of conditions will help us capture the effect of increasing uncertainty on the network.

The following chapters describe our probabilistic tool, methodology and some findings from this approach.

# 4.3 Probabilistic thermal analysis methodology

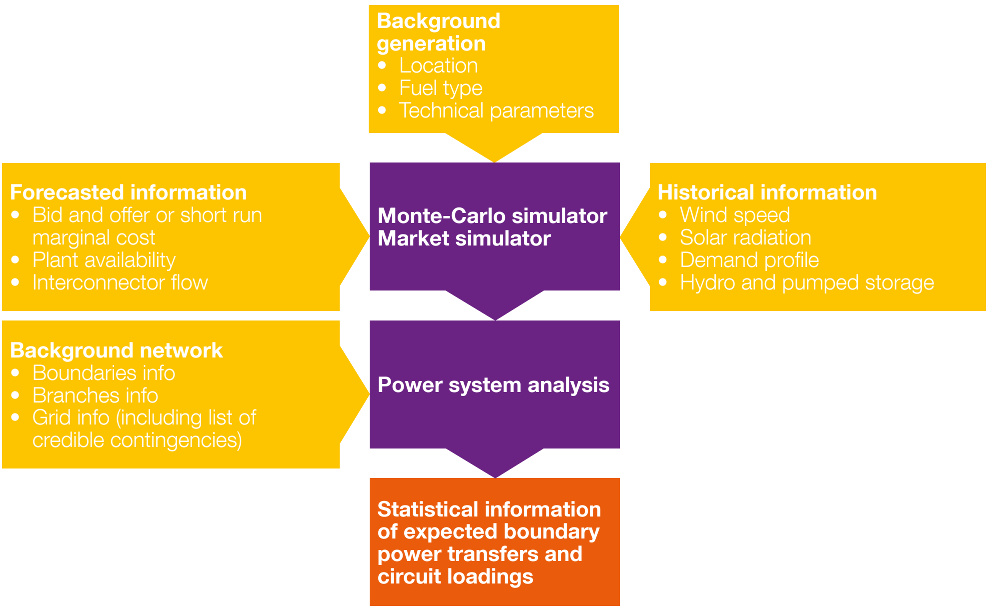
Our current probabilistic approach uses historical profiles, as inputs to the Monte-Carlo[2] simulator. This simulator samples historical inputs and uses the historical patterns of generation and demand to produce realistic outputs from wind farms, solar panels, hydro units, while accounting for generation units' availability and demand outturn. We use these outputs to estimate the likely power flow on individual transmission circuits or a group of circuits. A group of circuits are also known as a boundary as discussed in chapter 3.

When Monte-Carlo is used to sample likely background generation and demand conditions, it produces sequential hourly snapshots of generation and demand for each sample year.

Each snapshot is assessed by the electricity market simulator. This allows us to find out the probable economic dispatch of energy resources assuming an ideal electricity market. The results, which are hourly generation and demand snapshots, are evaluated by power system analysis based on direct current (DC) power flow. The results from the power flow analysis make us understand the impact on the GB NETS – where thermal constraints are most likely to be seen.

Our probabilistic approach can be summarised by two key elements – the Monte Carlo sampling economic dispatch and the DC power flow network assessor element. The overall probabilistic process is summarised in figure 4.1.

**Figure 4.1**
Probabilistic thermal analysis diagram




[2] A mathematical technique widely used to model risk and uncertainty

## Current limitations of our probabilistic approach

Considering that our current probabilistic approach is based on DC load flow, we cannot assess network voltage, reactive power flow or stability requirements. This limits our assessment to just thermal requirements for year-round probabilistic analysis. We have started an innovation project to explore options for developing a year-round voltage assessment tool as well as probabilistic voltage assessment methodologies. When we use the probabilistic approach to assess the network for thermal requirements (from either a circuit or boundary level perspective), we also need to assess the network's capability to meet these requirements.

Assessing the network's capability requires the use of network actions, namely, post-fault thermal ratings, Quadrature Booster (QB) tapping and other flexible AC transmission system (FACTS) devices – including HVDC control.

We are currently able to consider 6hr post-fault ratings and HVDC flow control. However, the QB tapping and utilisation of power control FACTS devices are not yet included in the tool. Therefore, our probabilistic tool is unable to calculate boundary capability like our deterministic approach.

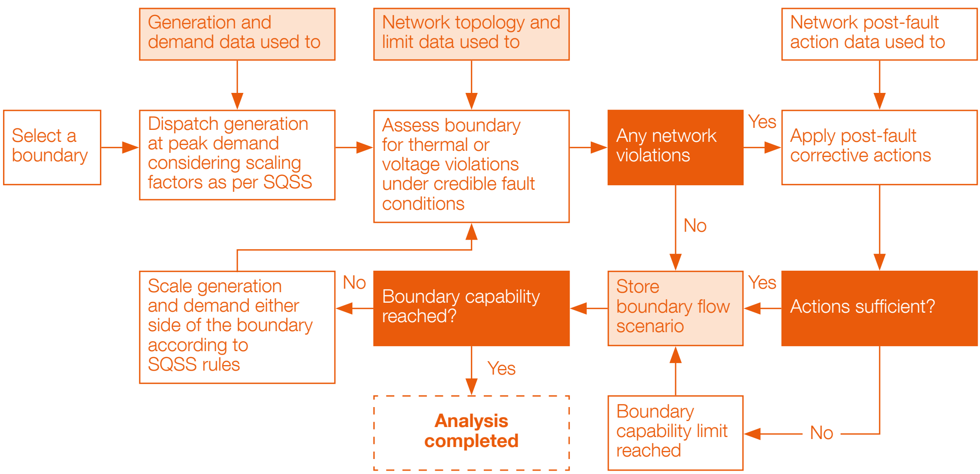
Towards the end of this chapter, we share with you our development pathway for our probabilistic tools. We plan to improve our process with all post-fault actions to enable us to calculate boundary capability from a thermal perspective, like our deterministic approach.

## Comparison with our deterministic approach

Developing our probabilistic approach has followed a 'learning by doing' process, which involved reconsidering our deterministic process to identify the steps in the process that we could enhance and incrementally evolve toward a full probabilistic analysis process.

Figure 4.2 summarises the key steps in our current deterministic process. This applies to both the thermal and voltage requirements and capability evaluation process.

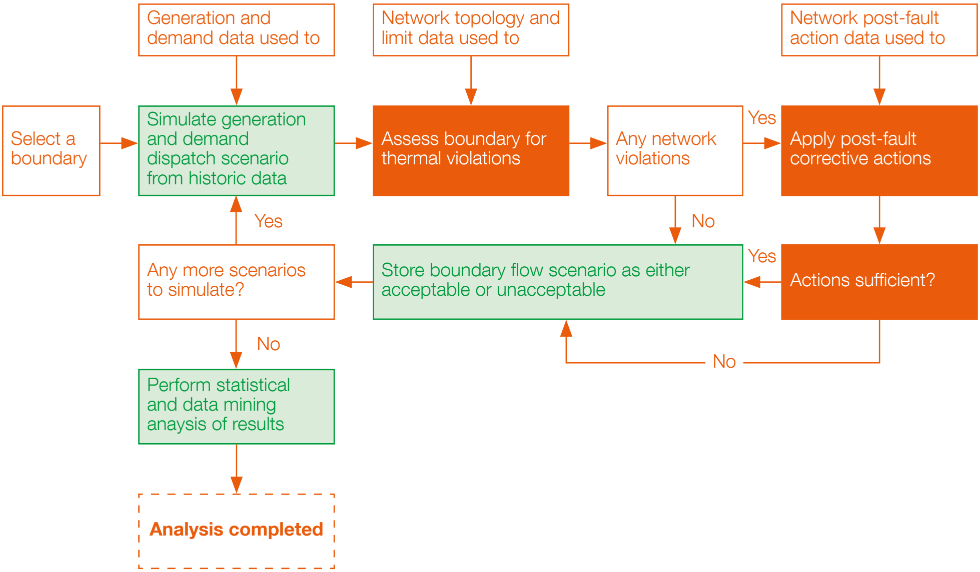
**Figure 4.2**
Key steps in the current deterministic analysis process



In figure 4.3, we show the key steps in our developing probabilistic process. This applies only to the thermal requirements evaluation process. The orange filled boxes show where we are still developing capability to match the deterministic process to do thermal capability assessments.

This is due to the limitations we discussed in the previous chapter. Thus, we're currently only able to partially model thermal overload network post-fault actions – limited to post-fault 6hr ratings and HDVC control actions. We present our development pathway later in chapter 4.5 on how we're working on the current limitations.

**Figure 4.3**
Key steps in our developing probabilistic analysis process for thermal analysis




The green highlights in figure 4.3 show the steps in our analysis which have been improved by our probabilistic approach.

## Summary of improvements achieved

Because we can produce several thousand generation and demand scenarios, we have improved on the number of network flow scenarios that we can produce over a wider timeframe (e.g. a season or a year). Our probabilistic tool can currently consider up to 87,600 year-round scenarios. This is because for each year (i.e. 8,760 hours) we can generate 10 variations of generation and demand backgrounds during each hour. We employ multivariate sampling techniques to preserve connections between sequential hours.

This leads to 87,600 network flows per studied boundary when it is intact. When contingencies are considered against a boundary, we can generate 87,600 network flows multiplied by the number of contingencies considered. We can, on average, generate this large number of outcomes within ten minutes of simulation.

## Summary of improvements being worked on

From this large number of network flow scenarios, considering both intact and contingency states, we can distinguish a network's state into either an acceptable or an unacceptable power flow state outcome. A condition is said to be acceptable where we do not see any violation of network thermal limits, whereas it is unacceptable if we see a violation of network thermal limits. We can currently distinguish these states after accounting for 6hr post-fault rating and HVDC flow control. However, we need to further account for QB tapping and utilisation of other power control FACTS devices to properly distinguish acceptable and unacceptable boundary flow states.

## What we can presently do with our probabilistic approach

We use these outcomes to perform analysis of network thermal requirements, using statistical and data mining approaches. We present a detailed discussion on acceptable and unacceptable power flow concepts including how we apply statistical and data mining analysis to identify and cluster network behaviour with generator behaviour in our case study in chapter 4.4.2. This helps us better understand requirements on the network.

Our improvements also enable us to use probabilistic generation and demand dispatch results to compare against our single snapshot generation and demand dispatch deterministic method. This helps us see how both the likely and worst-case dispatch scenarios compare between the two methods. We expand on this idea in our case study in chapter 4.4.1.

# 4.4 Thermal probabilistic case studies – winter season

## Background to case studies

Our winter peak study case has a generation capacity mix composed of about 68 per cent thermal, 21 per cent wind, 6 per cent interconnector and the remaining 5 per cent composed of various storage and renewable energy technologies – to supply the GB winter peak demand. These technologies are spread across the network. We apply a probabilistic analysis across the entire winter season considering these conditions.

Over the years, we've collected a database of historical information relating to hourly regional wind and solar profiles, plant availability (both forced and random outage data), and hydro and pumped storage typical loading patterns. We've applied this data to reflect our winter conditions. Also, using our modelling of the European market dispatch we've generated typical interconnector dispatches as well as energy storage charging and discharging cycles.

In order to validate the dispatches created by our probabilistic approach, we have compared our sampled Monte Carlo generation and demand dispatches with the historical data input. For our validation exercise, we compared the distribution of inputs against the distribution of outputs of generation plants. We present some validation results in figure 4.4a and 4.4b. In figure 4.4a, we show comparison of historical vs probabilistic offshore wind performance in the north of Scotland. In figure 4.4b, we show comparison of historical vs probabilistic performance of selected onshore wind. As can be seen, these results show very good alignment, which give us confidence in our probabilistic dispatch data.

**Figure 4.4a**
Selected offshore wind performance in the north of Scotland

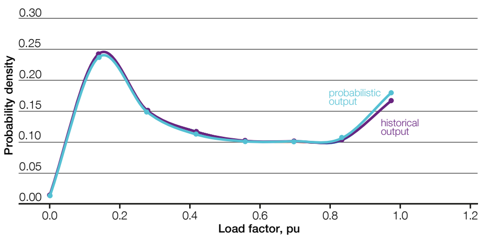
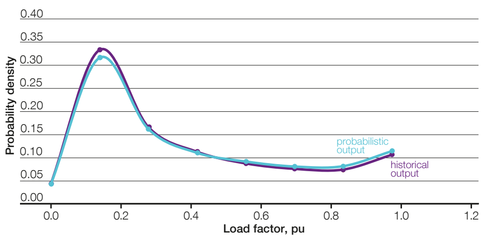



**Figure 4.4b**
Selected onshore wind performance



We have completed the validation exercise for all generation types and the results obtained confirmed that the tool's outputs reproduced input data with very good alignment. However, we are unable to fully publish these results as they may expose third party confidential information.

For our winter analysis, we generated around 22,000 scenarios of generation and demand dispatches. From this, considering both intact and contingency network conditions, we produced around 100,000 network flows, on average, per individual boundary. Assessment of the GB network was done at boundary level and we assessed 21 boundaries. The thermal loadings on lines within a two-substation distance of a studied boundary were recorded. If under either intact or fault conditions any of the recorded lines resulted in an overload, then the flow across the boundary was recorded and assigned as unacceptable. On the other hand, if under either intact or fault conditions any of the recorded lines did not result in an overload, then the flow across the boundary was recorded and assigned as acceptable.

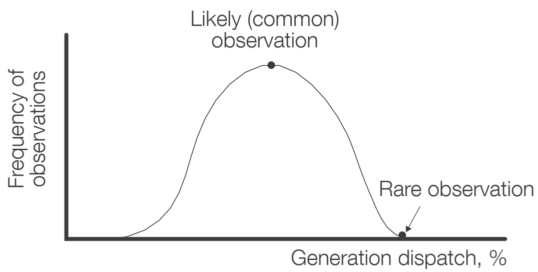
We use these results to present two main case studies in this chapter. The first case study will present the analysis of roughly 22,000 probabilistically defined generation and demand scenarios. The results are presented in chapter 4.4.1. In the first case study, we will use our probabilistic generation dispatches to compare with the deterministic dispatches we produce under our current planning methodology.

The second case study will present analysed results considering on average 100,000 probabilistic network analysis scenarios per studied boundary. The results are presented in chapter 4.4.2. In this case study, we will show how we statistically assess thermal requirements produced by probabilistic results of acceptable and unacceptable network outcomes.

## 4.4.1 Case study 1

This case study compares outcomes between probabilistic and deterministic assumptions regarding generation dispatch. Using figure 4.5, we can conceive a situation where generation dispatch can range from minimum to maximum output. Over several observations, we can produce a distribution that reflects both its likely and rare outcomes, as shown below. We can aggregate this information over wider geographical regions.

**Figure 4.5**
An illustration of the concept of the distributed outcome of dispatches

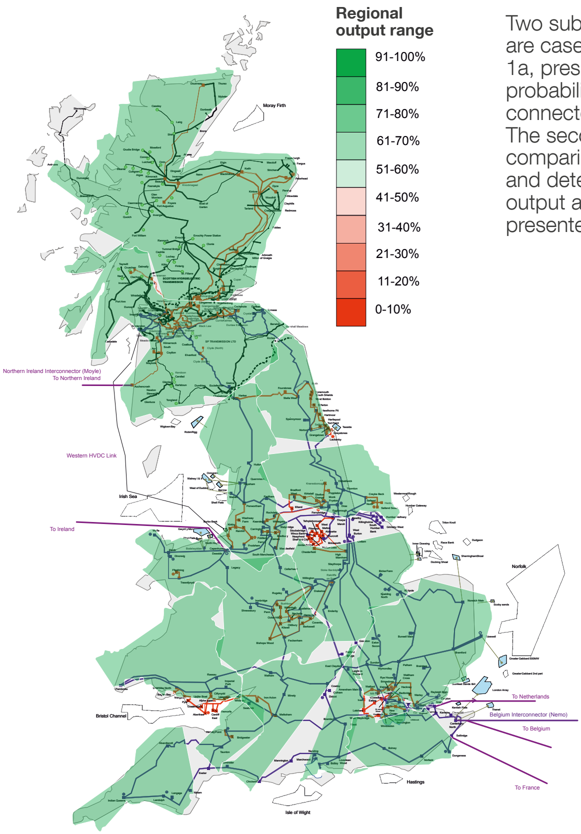


When aggregated over a region, or several regions, we can produce a map of dispatch outputs as shown in figure 4.6. This map is used to illustrate generation dispatches across the country and thereby is useful to show the differences between deterministic and probabilistic approaches. There is a scale on the map to show the % output related to a given region by a certain shade of either green or red colouring.

The map can be used to interpret the dispatch outcomes from either a deterministic or probabilistic case. For the probabilistic dispatch case, generation dispatch output, in per cent, in such a map is a calculated function of generator availability (e.g. forced or random outage), natural resource availability (e.g. wind or solar availability), the level of demand (as well as embedded generation dispatch) within the region and the price of generating electricity.

For the deterministic case, generation dispatch output, in per cent, in the map is a calculated function of the SQSS deterministic scaling rules. In this example, all regions are outputting between 61–70 per cent of their regional capacity.

**Figure 4.6**
An illustration of the concept of regional generation dispatch on the GB map. The map is conceptual and does not represent any dispatch scenario, but a visual example of how to interpret the map in the case studies to follow.




Two sub case studies are presented next, these are case study 1a and 1b. The first, case study 1a, presents a comparison between the likely probabilistic and deterministic transmission connected dispatch output at peak demand. The second, case study 1b, presents a further comparison between a worst-case probabilistic and deterministic transmission connected dispatch output at peak demand based on the concept presented in figure 4.5.

### 4.4.1.1 Case study 1a: assessing the deterministic and likely probabilistic planning assumptions

The peak demand level being considered in this case study is around 48 GW. The results to this study are presented in figure 4.7.

Figure 4.7a shows the regional transmission connected generation dispatches under the SQSS economy planned transfer assumption. To realise the regional dispatches only one scenario (i.e. a single snapshot) was created based on the deterministic definition of the generation dispatch at winter peak demand.

Figure 4.7b shows the likely regional transmission connected dispatches resulting from the probabilistic simulation approach. To realise these regional dispatches, multiple scenarios that matched the 48 GW demand level were produced based on probabilistic sampling rules mentioned earlier in chapter 4.3. Our probabilistic simulation produced several dispatch scenarios, and we then averaged these results (to represent the likeliest dispatch scenario at the 48 GW demand level) in a single map. This is what is shown in figure 4.7b.

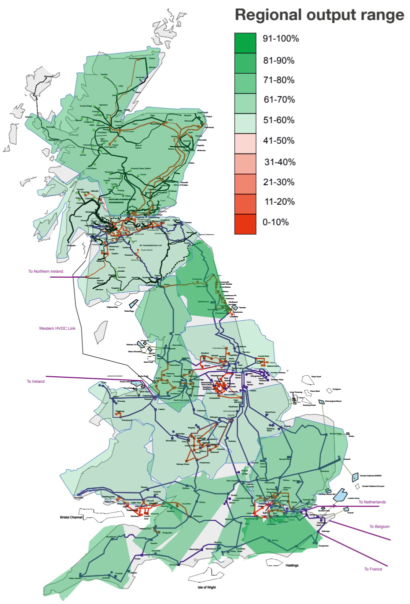
The deterministic map shows a dispatch profile across GB that varies between 51 and 70 per cent. This is the effect of scaling generation output using the deterministic rules. It results in a more evenly scaled generation dispatch, compared with the probabilistic dispatch case.

The probabilistic map shows a lot more regional variations in output. This variability is because input parameters like generator availability (e.g. forced or random outage), natural resource availability (e.g. wind or solar availability), the level of demand (as well as embedded generation dispatch) within the region are all simultaneously considered. The level of demand will vary due to embedded generation. However, to preserve the 48 GW gross peak demand scenario, we sum both the value of embedded generation and the net peak demand to arrive at the 48 GW value. These considerations result in the likely probabilistic dispatch shown in the figure 4.7b.

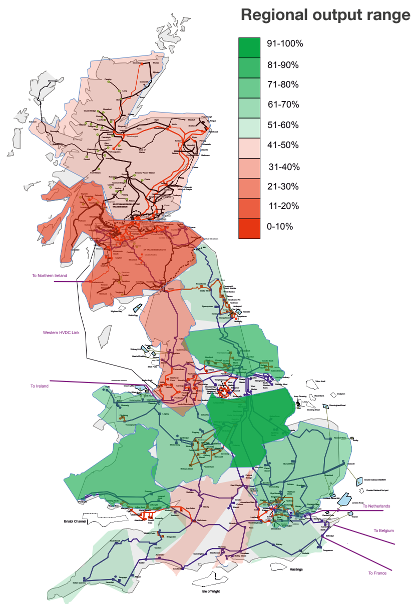
This comparison shows that the deterministic assumptions vary from the probabilistic case as it does not consider the variability of the input parameters that affect generator outputs. This is because the deterministic direct scaling factors look to bias dispatches so that areas with highest renewable concentrations and nuclear have higher dispatches and other plant types see relatively reduced dispatch. The probabilistic result suggests that deterministic dispatches for plant types like renewables may be optimistic and that for other plant types, like hydro and embedded generation, may be pessimistic.

**Figure 4.7**
Regional dispatch map with comparisons at winter peak demand:

**4.7a** Deterministic dispatch profile




**4.7b** Likely probabilistic dispatch profile




### 4.4.1.2 Case study 1b: Assessing the worst-case deterministic and probabilistic planning assumptions

As stated in 4.2, the long-term development planning of the NETS has traditionally been carried out against a single-snapshot worst-case scenario, at winter peak demand.

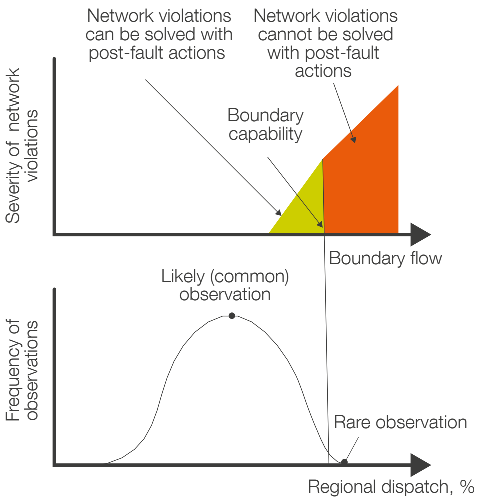
The winter peak boundary capability is achieved by selecting a boundary and initially dispatching the deterministic output. Generation and demand either side of the boundary are scaled up or down, as appropriate, to increase the flow across the boundary. If the network experiences violations that cannot be solved as the boundary transfer increases, then it is deemed to have reached its boundary capability. These are the numbers that have been calculated in chapter 3, per boundary.

In the following discussion, we show how we use probabilistic and deterministic results to compare how these two methods capture the worst-case scenario at peak demand.

A conceptual illustration highlighting the simple relationship between flows across a boundary and regional dispatch output is shown around the worst case condition in figure 4.8. The top part of the diagram shows that as power flow increases across a boundary, the boundary will experience an increase in the severity of network violations arising from credible faults. Initially, these violations can be solved using post-fault actions such as QB tapping or implementing post-fault ratings. However, there will be a point where these actions cannot match the increasing severity of violations. This point where the post-fault actions cease to be effective is where the boundary capability is defined. The bottom part of the diagram reflects what happens at the generation dispatch level. That is, as we increase boundary flow, we simulate dispatch conditions close to their worst–case outcomes as these will potentially be where the network faces the most stress.

In our case study, we assess boundaries B2, B4, B6 and SC3 at their boundary flow capabilities. We compare the regional generation dispatches at the capability limits of the boundaries – under both deterministic and probabilistic assumptions. The boundary flow capabilities at which we compare regional generation dispatches are derived from the respective boundary capabilities shared in chapter 3.

**Figure 4.8**
An illustration of the concept of the relationship between boundary flow and the distribution of dispatch outcomes




## B2 regional scaling map comparisons

Derived from chapter 3, the boundary capability flow for B2 is around 2,700 MW, and the B2 circuit crossing boundary line is highlighted in the map in figure 4.9. We see the deterministic regional transmission connected dispatch profile that produces this power flow level in 4.9a and the probabilistic regional transmission connected dispatch in 4.9b. In comparison to each other, we see that both maps show different regional dispatch levels.

The western leg of England and Wales are dispatched differently in the deterministic case compared to the probabilistic case. The main reasons for this are the distributed behaviour of embedded generation, varied interconnector output, coupled with varying wind output across regions (both offshore and onshore). The deterministic scenario does not account for these stated behaviours as it relies on evenly scaling generation output, based on the deterministic rules.

Focusing on the northern and southern Scottish regions, we see that in both regions more generation is dispatched in the northern Scottish region versus the south. In the deterministic assumption, this scenario is achieved by evenly scaling north Scotland up and evenly scaling south Scotland down. Under the probabilistic assumption, variation in regional wind output and the possible availabilities of generating plants are accounted for.

In the England and Wales network, in figure 4.9b, we see some regions where average transmission connected generation output is relatively low. This is due to high embedded generation dispatches, depressing demand and thus causing the low average transmission connected generation output in some regions and the wider spread in generation output across the wider GB landscape. The deterministic scaling method is more biased toward evenly scaling generation and demand, and results in dispatches that display relatively low variation in output between regions.

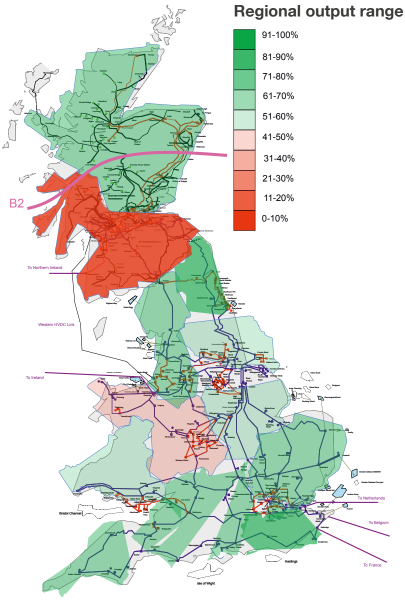
Overall, this comparison shows that the deterministic and probabilistic approaches model the worst-case generation dispatch conditions differently. In the probabilistic case, the intermittent sources connected to the network, such as embedded generation, are considered from their historical, technological and technical behaviour characteristics.

In the deterministic case, an 'even scaling' method is applied using scaling factors based on a generation technology alone not accounting for the technical behaviour of embedded generation and other sources of uncertainty and variability in the network.

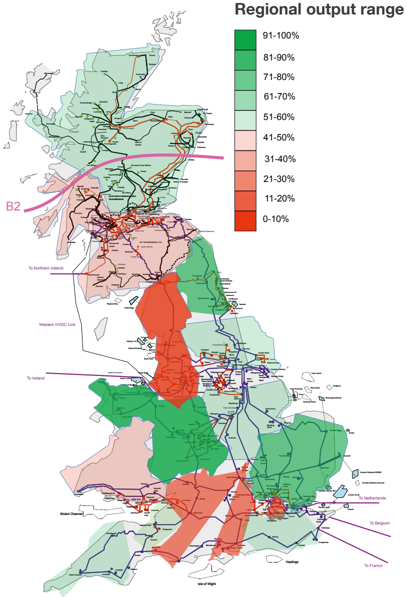
## Figure 4.9

B2 regional dispatch map comparisons:

**4.9a** Deterministic generation dispatches




**4.9b** Probabilistic generation dispatches




### B4 regional scaling map comparisons

Derived from chapter 3, the boundary capability flow for B4 is around 3,100 MW, and the B4 circuit crossing boundary line is highlighted in the map in figure 4.10. At this power flow, the diagram shows the deterministic regional generation dispatch profile in 4.10a and the probabilistic regional generation dispatch profile in 4.10b.

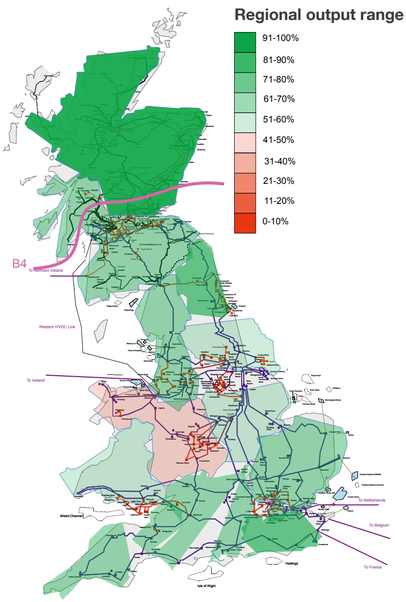
Looking at the deterministic case, we see how the 'even scaling' method scales generation in the north of Scotland to above 90 per cent to create conditions that realise the boundary capability flow of 3,100 MW. Contrasting this against the probabilistic case, we see that northern Scotland is dispatched at between 51 and 60 per cent of regional capacity to realise the same boundary flow.

To understand why these dispatch scenarios are different, in the probabilistic assumption we consider the regional impact of around 10–15 GW of dispatched embedded generation. This embedded generation is comprised of varied technologies and thus exhibits different dispatch patterns.

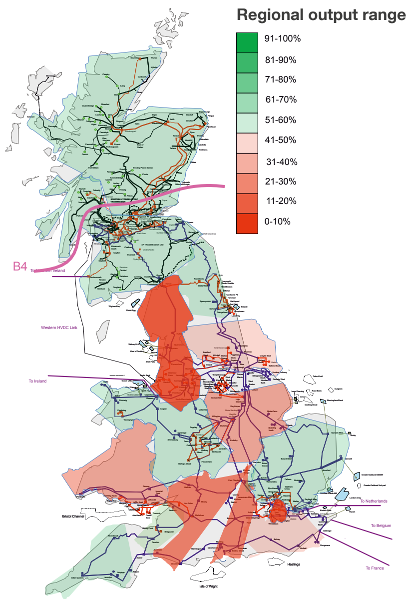
Much of the embedded capacity is found in England and Wales – therefore, in the probabilistic case, many regional dispatches in England and Wales are lower than the deterministic case. In the deterministic case, the embedded generation is evenly scaled, explaining why we see high regional dispatch outputs in figure 4.10a.

Consequently, for power to flow across B4, generation in the north of Scotland must be higher than that in the south of Scotland, leading to the above 90 per cent dispatch in north Scotland. The probabilistic map shows that for the flow of 3,100 MW to occur, wind does not need to be dispatched beyond 60 per cent of its regional capacity in the north of Scotland. This is much lower than the 90 per cent regional dispatch in the north of Scotland, as suggested by the deterministic results. Wind must be dispatched higher in the deterministic case because it doesn't adequately account for the behaviour of embedded generation.

**Figure 4.10**
B4 regional dispatch map comparisons:
**4.10a** Deterministic generation dispatches




**4.10b** Probabilistic generation dispatches




Overall, this comparison exercise shows that treatment of embedded generation results in the deterministic method generating scenarios that are found more toward (and possibly beyond) the very rare end of the dispatch distribution profile.

## B6 regional scaling map comparisons

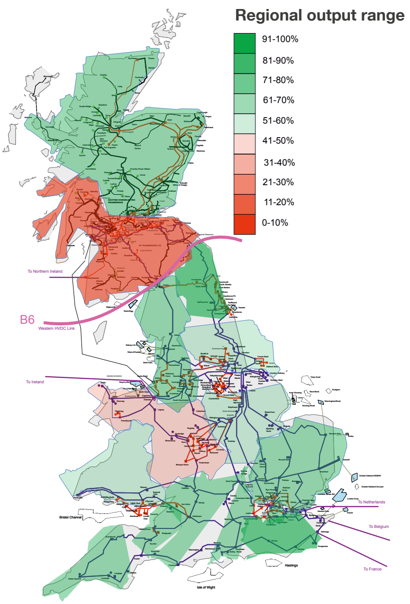
Derived from chapter 3, the boundary capability flow for B6 is around 5,700 MW, and the B6 circuit crossing boundary line is highlighted in the map in figure 4.11. At this boundary flow level, figure 4.11 shows the deterministic regional generation dispatch profile in 4.11a and the probabilistic regional generation dispatch profile in 4.11b.

We see a wide difference between both maps. In Scotland, the north dispatches more output in the deterministic case than the probabilistic case. The opposite outcome is true for the south of Scotland.

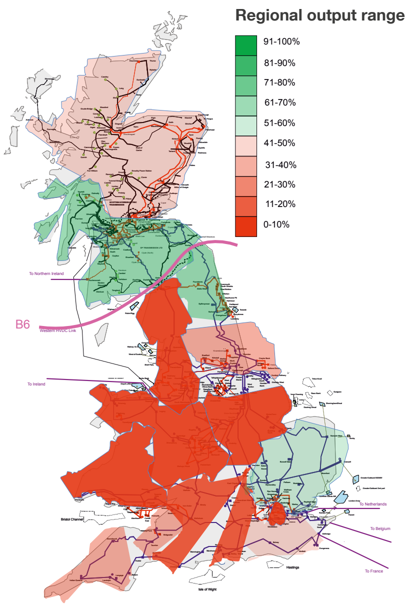
The B6 boundary cuts through the border between Scotland and England. Therefore, power across B6 is also influenced by the generation dispatch profile in England. In the probabilistic case, we see a dispatch situation in England and Wales heavily influenced by embedded generation (deep red regions). The deterministic method is unable to capture this scenario and instead sees comparatively higher England and Wales dispatches as the condition that leads B6 to its capability limit.

Like the B4 assessment earlier, because embedded generation behaviour isn't being adequately accounted for, we're seeing the deterministic case having to model high dispatch scenarios to find B6's capability point.

**Figure 4.11**
B6 regional dispatch map comparisons:
**4.11a** Deterministic generation dispatches




**4.11b** Probabilistic generation dispatches

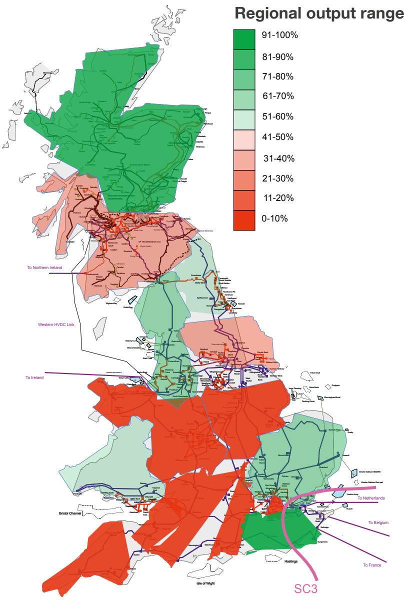



## SC3 regional scaling map comparisons

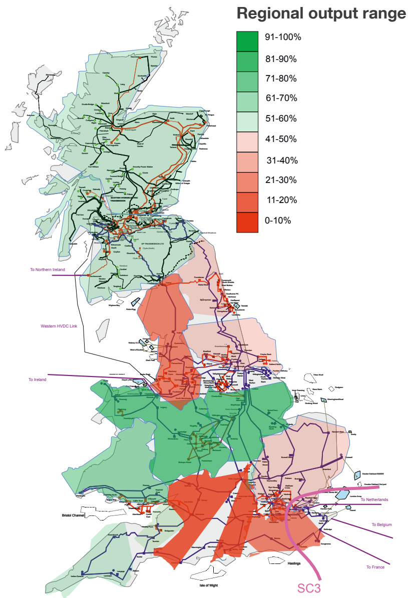
Derived from chapter 3, the boundary capability flow for SC3 is around 6,000 MW, and the SC3 circuit crossing boundary line is highlighted in the map in figure 4.12. At this boundary flow level, figure 4.12 shows the deterministic regional generation dispatch profile in 4.12a and the probabilistic regional generation dispatch profile in 4.12b.

**Figure 4.12**
SC3 regional dispatch map comparisons:

**4.12a** Deterministic generation dispatches




**4.12b** Probabilistic generation dispatches




In the deterministic case, we see that to find SC3's capability, the London and the Midlands regions will have to reduce their generation output to within 10 per cent of their regional capacities. Coupled with this, the south east will have to increase its output to above 90 per cent of its regional capacity. This creates the condition to push power of 6 GW out across SC3. The rest of the GB is scaled to balance the network and account for network losses.

In the probabilistic case, we see that even when regional output of the south east is between 30 and 40 per cent the SC3 boundary can see conditions that will push around 6 GW of power across the boundary at its capability limit. This condition is true as long as London and south central England have lower regional generation output than the south east, as this disparity is what will account for the increased flow across SC3. Also there is not a lot of demand in the south east relative to the generation capacity, so most of its generation will go out of the boundary. This is the case so long as the interconnectors are importing from Europe.

Once again we see that the different assumptions utilised in the deterministic and probabilistic approaches result in different worst-case generation dispatches.

### Key findings from regional scaling map comparisons

In this chapter, we compare the probabilistic generation dispatch against the deterministic generation dispatch approach. We noted that both methods produce different likely and worst-case generation dispatch profiles. This was shown to be the case at both peak demand and boundary capability flow level. The main reason for the different dispatch outcomes was attributed to assumptions around how generation is dispatched.

In the deterministic case, to generate the dispatch, scaling factors as a percentage of generator technology type capacity are used. In the probabilistic case, generating the likely dispatch follows the sampling of historical data and the modelling of generator type behaviour to produce a distribution of dispatches from which the likely dispatch is derived. The worst-case under deterministic assumptions are modelled using the even scaling method that attempts to push more power across a boundary until the boundary's limit is reached. The probabilistic method derives the worst-case dispatch scenario from the Monte Carlo generated distribution of dispatches. This way, the probabilistic method better captures the uncertain behaviour of generating units.

As generation, characterised by uncertain dispatch behaviour, connecting to the network increases, relying on the deterministic method to identify a credible range of dispatch scenarios will become more difficult. As shown from our studies, the deterministic method, in some cases, produces dispatches such as wind and embedded generation that, respectively, are over or under-estimated in relation to historical data. Our probabilistic results can therefore be used to model a variety of uncertain network planning inputs to identify common dispatch scenarios that could be modelled as sensitivities to enhance the deterministic method.

## 4.4.2 Case study 2: Using probabilistic analysis to identify complex network requirements

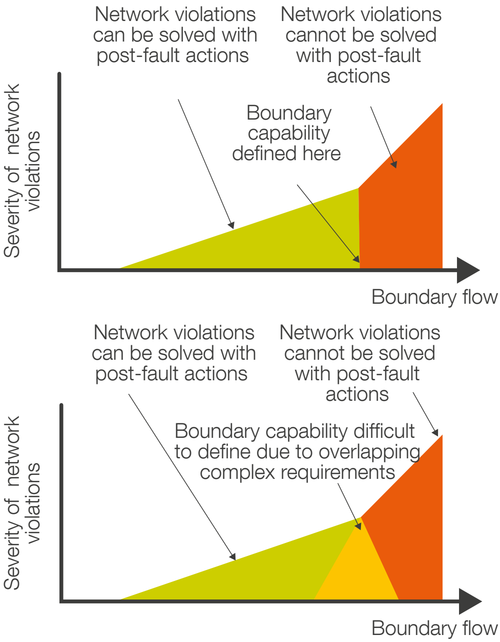
The previous case study showed the need to properly account for rising uncertainty on the network in order to dispatch realistic generation and demand scenarios. In this chapter, we aim to show that it is also important to understand the impact of uncertainty on network requirements. A network requirement is the need to transfer power from a generating source to a demand centre across an electrical boundary. As mentioned earlier, to meet a requirement, a network can either experience violations to its operating limit or it can allow power to flow through it without exceeding its planning limit.

Network requirements are acceptable when no violations are experienced in the effort to make power flow from generation to demand across a given boundary. Network requirements are unacceptable when there is potential for circuit overloading at a given boundary power transfer level. This unacceptable condition would typically be managed by implementing post-fault actions to clear the violation. If as power transfer increases and the post-fault actions become ineffective then the boundary is judged to have reached its capability limit.

When the deterministic method is used to establish boundary capability, it increases power transfer across a boundary, and by implementing post-fault actions it is able to reach a point where the boundary capability is established. This is illustrated in figure 4.13 (top). A limitation with this approach is that it defines a boundary capability at a point where the acceptable region smoothly transitions to an unacceptable region. Figure 4.13 (bottom) shows that acceptable and unacceptable requirements do overlap and, as a result, defining a network capability level is more complicated.

A network is defined to have complex requirements when two or more dispatch scenarios across a boundary produce the same boundary power flow, but different acceptable and unacceptable network requirement outcomes.

**Figure 4.13**
An illustration of the concept of complex network requirements




With our probabilistic process, because many dispatch scenarios can be produced, we can capture both acceptable and unacceptable scenarios. We can statistically assess these results to better understand the complex requirements on our network by assessing overlap regions. The single snapshot deterministic dispatch method can capture either an acceptable or an unacceptable scenario occurring on the network – but not both.

As mentioned in chapter 4.3, our probabilistic approach is not able to capture the full post-fault capability of the network. This means we can use dispatch scenarios to capture the requirements on the network but not the capability of network. Thus, at present, the results we share in this chapter cannot be considered in the NOA analysis until developments to address these limitations are completed. We are developing our process to account for a fully flexible network.

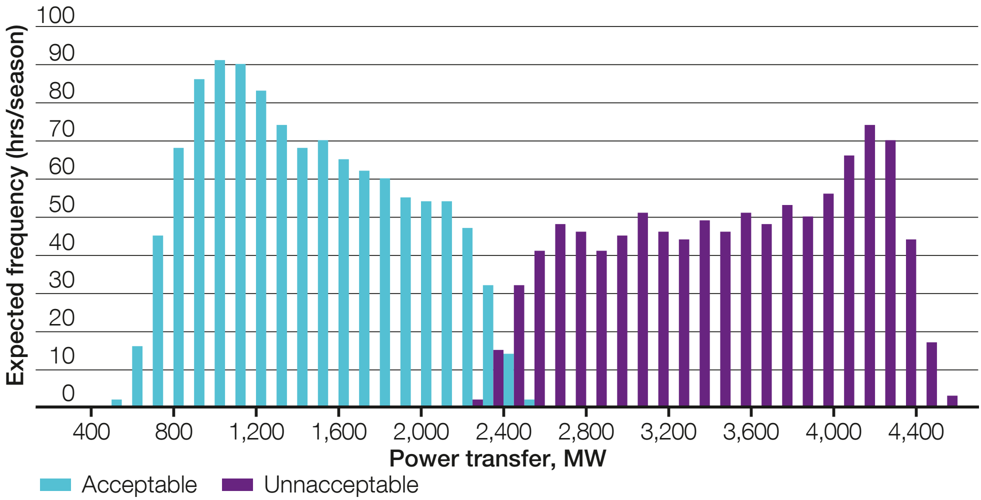
We discuss this further at the end of the chapter. Nevertheless, here we aim to show how we are developing our probabilistic process to enable us to capture and make sense of complex network requirements.

In the next chapters, we show our results for a selection of boundaries B2, B4, B6 and SC3. These results show distributions of acceptable and unacceptable plots, as well as their overlapping transfer regions. We then investigate the power flow at which we observe the most number of acceptable and unacceptable outcomes to better understand the complex nature of power transfer network requirements as arising from a varied mix of generating sources characterised by wide ranging behaviour.

### 4.4.2.1 Using probabilistic analysis to assess complex network requirements on B2

An example on how to assess the complex requirements on B2 is illustrated through analysis of the dispatch pattern at the power transfer of 2,350 MW. This boundary power transfer level is considered as it captures one of the highest acceptable and unacceptable outcomes at a single power transfer level as shown in figure 4.14.

**Figure 4.14**
Probabilistic transfer plots of acceptable and unacceptable power transfers for B2 winter 2019/20 (note – the overlap region would shift to a higher power transfer level if QB actions were accounted for in our analysis)



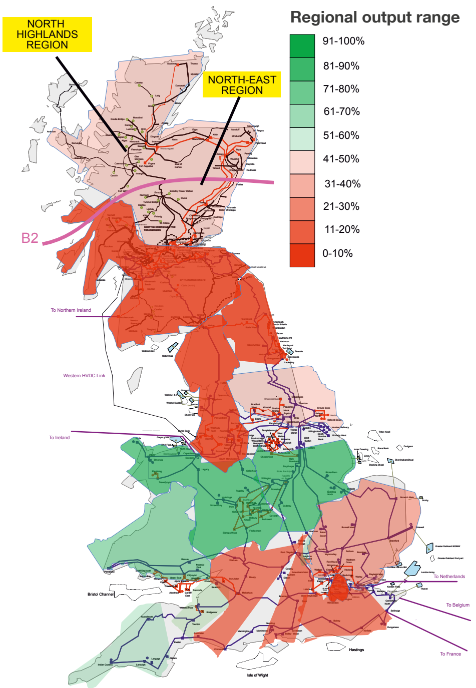

Resulting from this, in figure 4.15a, we have the likely regional transmission connected dispatch profile map of acceptable power flow across the boundary. In figure 4.15b, we have the likely transmission connected dispatch profile map of unacceptable power flow across the boundary.

The acceptable and unacceptable conditions are driven by different dispatch patterns that, although they result in the same boundary transfer, result in no network violations (figure 4.15a) and in some network violations (figure 4.15b).

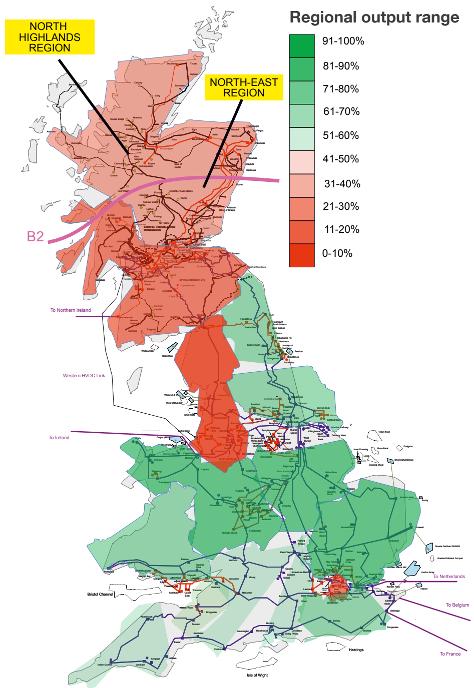
Upon data mining our results, we observed that in the case of figure 4.15a, there is a relatively equal contribution of wind output from both north east Scotland and north highland Scotland. This dispatch scenario produced more balanced network flows which thus helps avoid network violations. In the case of figure 4.15b, we found that for periods when the output in the north east is relatively high and conversely when output is relatively low in the north highlands, there are unacceptable flows. This is because this scenario concentrated flows through the weaker part of the network. We assessed these power transfer dispatch conditions in our deterministic study and found that the network has flexible assets and post-fault actions that could solve these constraints and thus does not represent a true network constraint.

**Figure 4.15**
Regional dispatch maps for B2 at 2,350 MW boundary export flow:

**4.15a** Acceptable regional dispatch map




**4.15b** Unacceptable regional dispatch map




The regional map, in figure 4.15a, shows that the overall transmission connected dispatch level in northern Scotland region is slightly higher than that observed in figure 4.15b. However, the overall dispatch level in southern Scotland in figure 4.15a is lower than that observed in figure 4.15b. Therefore, the power transfer across B2 is maintained in both cases.

In our probabilistic analysis, we have accounted for a combination of wind output differences between north highlands and north east Scotland to better understand what's influencing the overlapping requirements across B2. Our probabilistic approach helps us to more fully capture network requirements because it allows us to model multiple dispatch scenarios. This enhances our current planning approach that uses single snapshot dispatch scenarios by improving our understanding of complex network needs.

### 4.4.2.2 Using probabilistic analysis to assess complex network requirements on B4

Like B2, for B4 we assess the complex overlapping requirements through analysis of the dispatch pattern at the power transfer of 3,000 MW. This boundary power transfer level is considered here as it captures one of the highest acceptable and unacceptable outcomes at a single power transfer level as shown in figure 4.16. Resulting from this, in figure 4.17a we have the likely transmission connected dispatch profile resulting in an acceptable power flow across the boundary. In figure 4.17b, we have the likely transmission connected dispatch profile resulting in an unacceptable power flow across the boundary.

Once again, we use data mining techniques to observe that in the case of figure 4.17a when the output in the north east is high and low in Argyll (or vice versa), there are acceptable flows. The acceptable flows from these scenarios are compounded by the influence of the (relative to the unacceptable case) lower contribution of embedded generation in the region. The difference between figure 4.17a and figure 4.17b in embedded generation dispatch is approximately 21 per cent.

In the case of 4.17, we found that for periods when there is a relatively equal contribution of wind output from both north east Scotland and Argyll and Bute, coupled with a much higher contribution from embedded generation, the result was more unbalanced network flows. The effect of this situation concentrated flows through the weaker part of the network. We assessed these power transfer dispatch conditions in our deterministic study and found that the network has flexible assets and adequate post-fault actions that could solve these constraints and thus does not represent a true network constraint.

**Figure 4.16**
Probabilistic transfer plots of acceptable and unacceptable power transfers for B4 winter 2019/20 (note – the overlap region would shift to a higher power transfer level if QB actions were accounted for in our analysis)

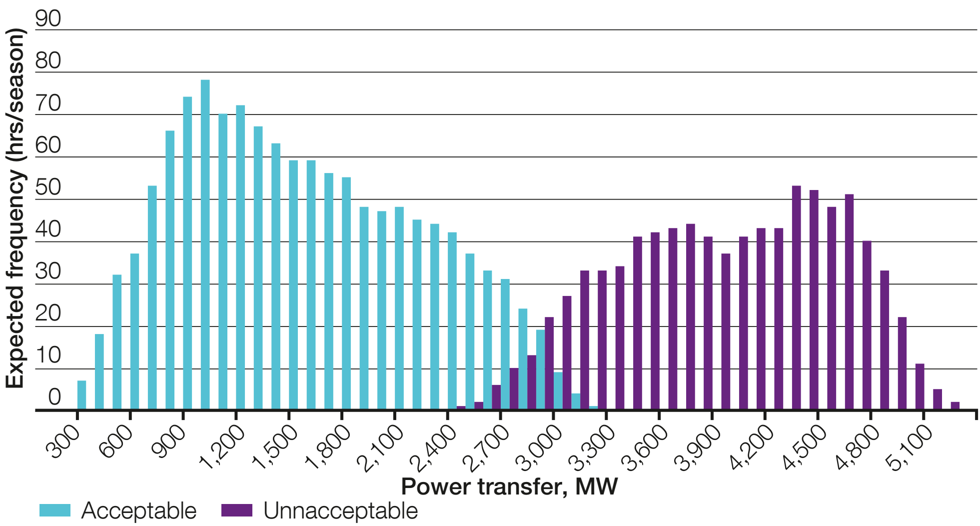
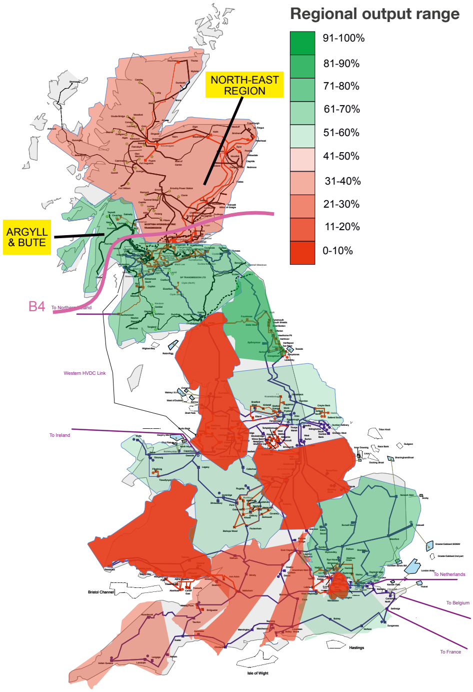
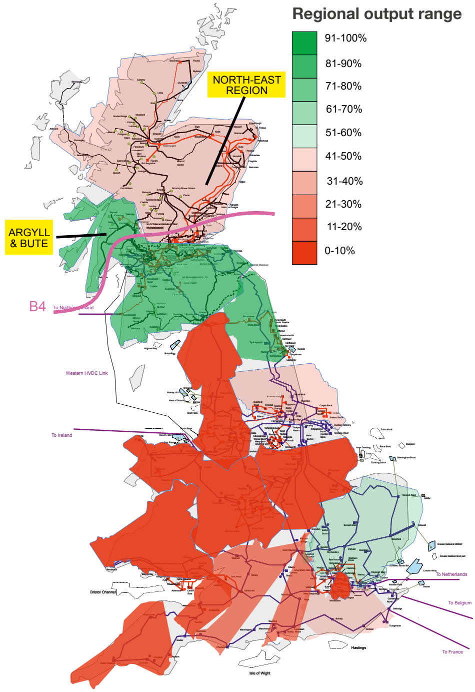


**Figure 4.17**
Regional dispatch maps for B4 at 3,000 MW boundary export flow:

**4.17a** Acceptable regional dispatch map




**4.17b** Unacceptable regional dispatch map




The regional map in figure 4.17a shows that the average regional output for the Scottish region is lower than the one in figure 4.17b. However, the output range in figure 4.17b for the England and Wales region is lower than figure 4.17a. This, therefore, coupled with the impact of embedded generation differences earlier mentioned still produce a similar power transfer level across B4.

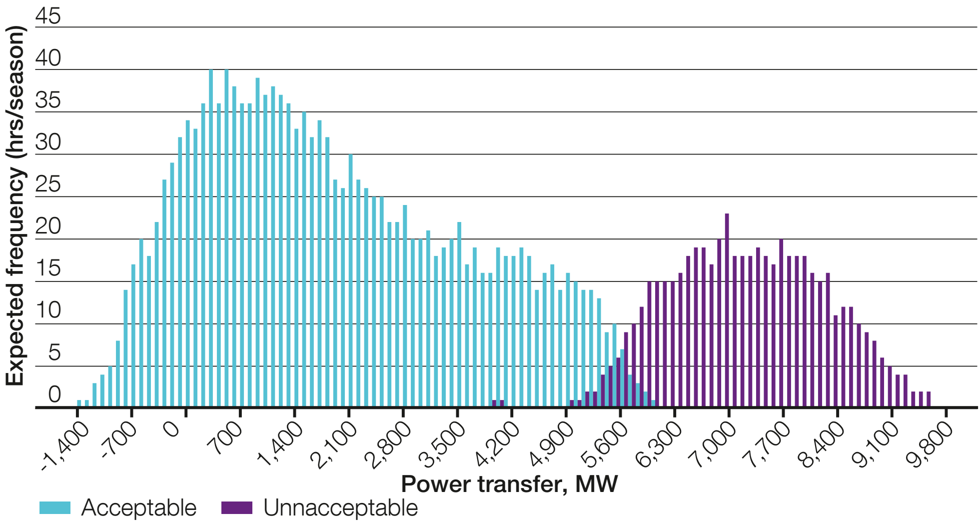
In our probabilistic analysis, we have accounted for a combination of embedded generation dispatches, and wind output differences between Argyll and Bute and north east Scotland to better understand what's influencing the overlapping requirements across B4. Relying on a single snapshot to capture the above-mentioned output differences is not possible.

### 4.4.2.3 Using probabilistic analysis to assess complex network requirements on B6

Considering that it is the power transfer level that sees the most combination of acceptable and unacceptable outcomes, we assess the complex overlapping requirements on B6 analysis at 5,600 MW. This boundary power transfer level is considered here as it captures one of the highest acceptable and unacceptable outcomes at a single power transfer level as shown in figure 4.18.

**Figure 4.18**

Probabilistic transfer plots of acceptable and unacceptable power transfers for B6 winter 2019/20 (note – the overlap region would shift to a higher power transfer level if QB actions were accounted for in our analysis)



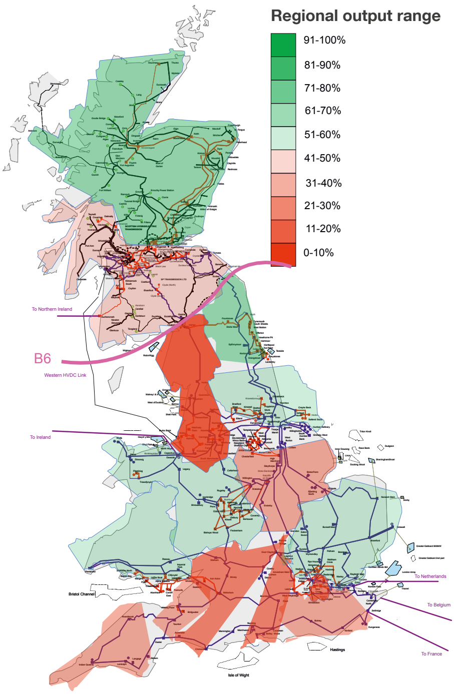

In figure 4.19a, we have the likely dispatch profile resulting in an acceptable power flow across the boundary. In figure 4.19b, we have the likely dispatch profile resulting in an unacceptable power flow across the boundary.

Using data mining techniques, we observe that, especially within the England and Wales region, the output range in figure 4.19a is higher than in figure 4.19b. The reason for this difference in dispatch is once again related to the difference in embedded generation dispatch between figure 4.19a and figure 4.19b, which is approximately 20 per cent. Figure 4.19b has a higher embedded generation dispatch than figure 4.19a. When there is relatively lower embedded generation contribution, we notice that flows around B6 are more balanced and do not result in network constraints. However, when there is relatively higher embedded generation contribution, we notice that flows around B6 are less balanced and result in network constraints.

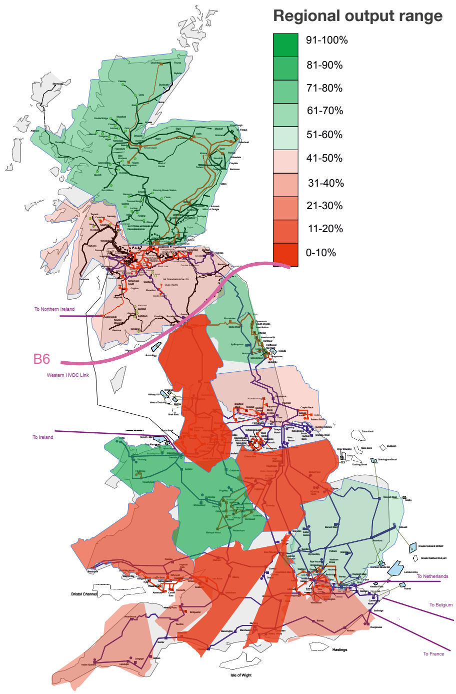
In our probabilistic analysis, we have accounted for embedded generation dispatches to better understand what's influencing the overlapping requirements across B6. We assessed these power transfer dispatch conditions in our deterministic study and found that the network has flexible assets and post-fault actions that could minimise the amount of these constraints.

**Figure 4.19**
Regional dispatch maps for B6 at 5,600 MW boundary export flow:

**4.19a** Acceptable regional dispatch map




**4.19b** Unacceptable regional dispatch map



### 4.4.2.4 Using probabilistic analysis to assess complex network requirements on SC3 boundary export conditions

Considering that it is the power transfer level that sees the most combination of acceptable and unacceptable outcomes, we assess the complex overlapping requirements on SC3 analysis at 5,000 MW. This is shown in figure 4.20.

In figure 4.21, we have the likely dispatch profile resulting in an acceptable power flow across the boundary. In figure 4.21b, we have the likely dispatch profile resulting in an unacceptable power flow across the boundary.

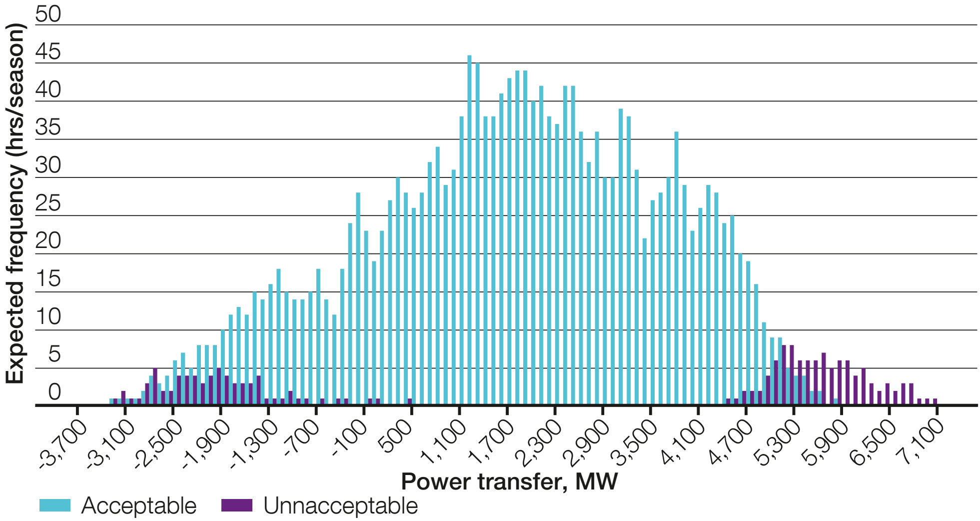
We observe that in the case of figure 4.21a, the Scottish regional dispatch profile is lower than in figure 4.21b. This is influenced by higher dispatch, in figure 4.21a, coming from England and Wales, especially from the East of England and the South East of England, under heavy interconnector import conditions.

In figure 4.21b, we see that when dispatches from the East of England and the South East of England are relatively lower (than in figure 4.21a), there are constraints that arise around the SC3 boundary region. In this case, there is a combination of opposing interconnector activity (i.e. some interconnectors are importing while others are exporting) and low wind output resulting in unusual flow patterns. This leads to violations on the part of the network in the SC3 region that is configured to deal with high fault levels, resulting in an unbalanced network topology that is more easily susceptible to violations at low power flow patterns arising from specific and rare generation dispatch outcomes. In both cases, the dispatch from embedded generation is similar and does not impact our analysis.

This susceptibility diminishes under the situation that interconnectors in that region are all importing from Europe and wind output in the east of England and south east of England is relatively high. The power transfer level under these two conditions is the same and is explained by the dispatch patterns shown in the figure for the Midlands, South Wales and the Humber regions.

We assessed these power transfer dispatch conditions in our deterministic study and found that the network has flexible assets and post-fault actions that could solve these constraints and thus does not represent a true network constraint.

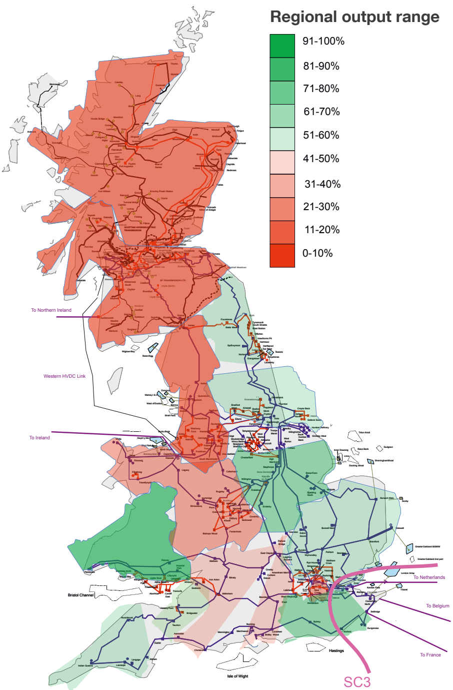
**Figure 4.20**
Probabilistic transfer plots of acceptable and unacceptable power transfers for SC3 winter 2019/20 (note – the overlap region would shift to a higher power transfer level if QB actions were accounted for in our analysis)



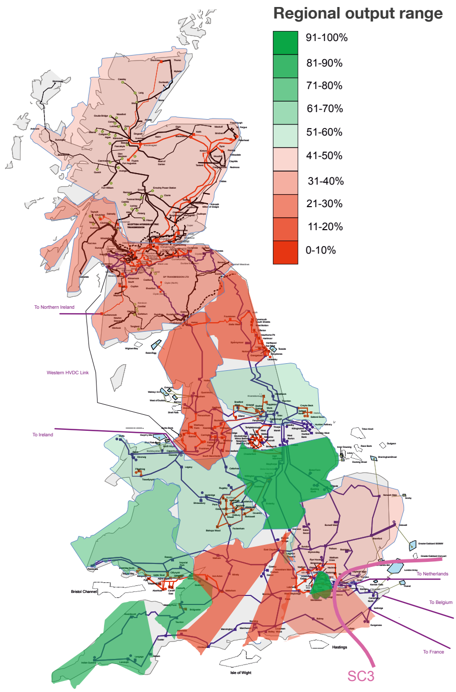
## Figure 4.21

Regional dispatch maps for SC3 at 5000 MW boundary export flow:

**4.21a** Acceptable regional dispatch map




**4.21b** Unacceptable regional dispatch map



### 4.4.2.5 Using probabilistic analysis to assess complex network requirements on SC3 boundary import conditions

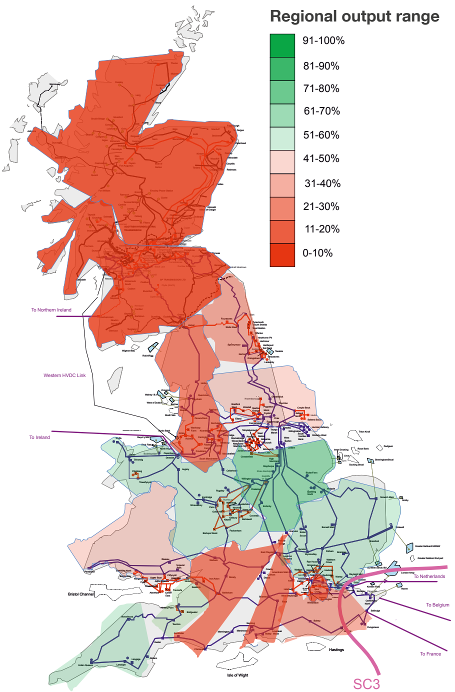
We assess the complex overlapping requirements on SC3 analysis at -2,000 MW as it is the power transfer level that sees the most combination of acceptable and unacceptable outcomes. This is shown in figure 4.22.

In figure 4.22a, we have the likely dispatch profile resulting in an acceptable power flow across the boundary. In figure 4.22b, we have the likely dispatch profile resulting in an unacceptable power flow across the boundary.

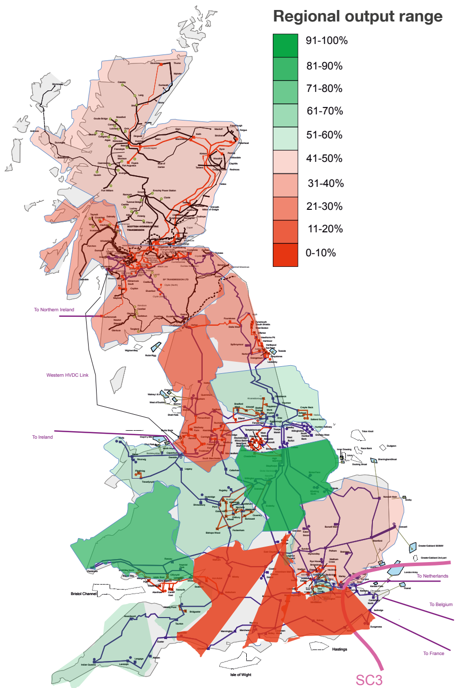
**Figure 4.22**

Regional dispatch maps for SC3 at -2,000 MW boundary import flow:

**4.22a** Acceptable regional dispatch map




**4.22b** Unacceptable regional dispatch map




Looking at our plots for SC3, we see that high dispatch in the South East of England (figure 4.22a) does not result in network violations. This is because a high presence of embedded generation across GB (24 per cent more in this case compared with the unacceptable case) influences network flows such that constraints are not experienced.

The higher dispatch in figure 4.22a compared to figure 4.22b is also influenced by low wind output in Scotland. When the output in Scotland is high (figure 4.22b) and the GB demand being served is high, the output in the east of England and the south east of England is low. This is compounded by interconnector activity exporting into Europe.

## Key findings from the assessment of complex network requirements

In this chapter, we've used our probabilistic generation dispatch outputs to capture both acceptable and unacceptable scenarios on the network. For boundaries B2, B4, B6, SC3 export and SC3 import at the power flows of 2,350 MW, 3,000 MW, 5,600 MW, 5,000 MW and –2,000 MW respectively we performed data mining to understand the dispatch conditions driving both acceptable and unacceptable outcomes.

In a number of boundaries, we saw that very high embedded generation output results in unacceptable flows. Compounding this, for B2 we saw that negatively correlated wind output scenarios between North Highland and north east Scotland led to unacceptable B2 flows. For B4, positively correlated wind output scenarios between Argyll and Bute and the north east of Scotland resulted in unacceptable B4 flows. When the above-mentioned regions were oppositely correlated to the earlier conditions, and embedded generation dispatch was lower, then there were acceptable flows across B2 and B4. B6 is mainly influenced by embedded generation dispatch – when it is higher there are unacceptable flows and when it's low there are acceptable flows.

For SC3, we observed that when it was exporting power and the interconnectors in its boundary region were negatively correlated, then unacceptable flows arose. If the interconnectors were positively correlated, then the boundary experienced acceptable flows. When SC3 operated in the boundary importing mode, if the level of embedded generation output was low then it experienced unacceptable power flows, and if the level of embedded generation output was high then it experienced acceptable power flows.

We can therefore capture common boundary drivers as well as boundary specific drivers that explain both the acceptable and unacceptable outcomes at a given power transfer.

# 4.5 Development pathway and integration into our planning process

We have shown that the deterministic single-snapshot methodology based on the scaling factor might over or under-estimate network requirement and subsequently the boundary capability – due to the changing nature of the energy system, higher levels of uncertainty and highly variable generation and demand.

Furthermore, the year-round probabilistic technique looks at a broader range of snapshots and identifies a lot more network requirements than the traditional approach applied to boundary analysis. This makes it possible to move toward circuit-based rather than boundary analysis. This allows us to improve our analysis because we may identify situations where we can avoid over-investment. Also, we might identify situations that require further investment – for other boundaries and/or different background conditions. Thus, probabilistic results widely vary and cannot be applied generically but per background and boundary conditions.

We are continually working to extend our tools' functionalities. Our probabilistic work is one of our pathfinder projects, where we are learning by doing and are shaping our thinking as we apply our new tools to real data. We are in the early stage of this pathfinder and are investigating various techniques to integrate year-round probabilistic analysis into our planning process. We have initiated developments to integrate pre- and post-faults actions (e.g. automated QB tapping) into our probabilistic tool. We have also started an innovation project to explore options for developing a new voltage assessment tool as well as probabilistic voltage assessment methodologies.

Last year, we presented a methodology based on "constrained forecast error" to choose one capability number per season from the probabilistic analysis. It determines a number to balance the acceptable and unacceptable power transfers based on "energy at risk" and "opportunity lost" concepts. We are exploring other options to integrate probabilistic analysis into *NOA*. We are also looking at integrating year-round probabilistic techniques into our CBA analysis for *NOA* and developing a bespoke joint market and network tool for GB probabilistic thermal analysis. Currently the probabilistic approach isn't part of the existing *NOA* process as it only accounts for thermal analysis.

**Figure 4.23**
Development pathway for our probabilistic pathfinder project

| *ETYS 2018* | *ETYS 2019* benchmark studies | *ETYS 2020* | *ETYS 2021* |
|---|---|---|---|
| • Case study for one boundary.<br>• Present preliminary results in *ETYS 2018.* | • Further development of our probabilistic tool including increasing its capability to speed up the process.<br>• All year 1 boundaries studied.<br>• Data mining on results. | • Initiate developments to integrate pre and post-fault actions (automated and manual).<br>• Update on development of new voltage assessment tool.<br>• Develop techniques to calculate dynamic boundary capability. | • Proof of concept for a bespoke joint network and market tool for probabilistic thermal analysis.<br>• Proof of concept for integration of probabilistic network analysis into *NOA* process including ESO optimisation actions. |

# 4.6 Share your feedback

We welcome your feedback on the document to help us explore how we can further develop our probabilistic tools and analysis. We are arranging a webinar in early 2020 to share our probabilistic planning developments with you. In the meantime, please share your views with us via **transmission.etys@nationalgrideso.com**

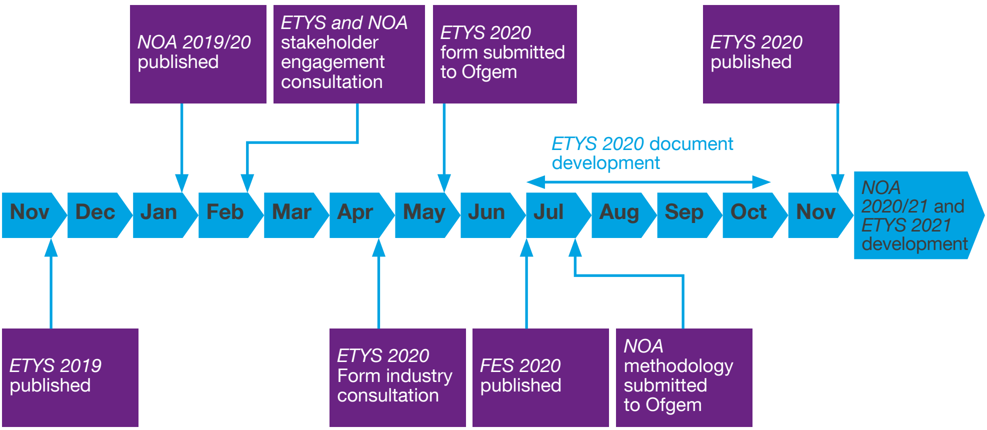
# Chapter 5
## Way forward

**The *ETYS* and *NOA* documents are continually evolving to meet our ambition set out in the ESO Forward Plan. As the documents expand to a wider audience, we hope you will help shape them to become even more valuable for you and others to use.**

# 5.1 Stakeholder engagement

**We would like to hear your views on how we should shape both *ETYS* and *NOA* documents to make them more valuable. Our draft timetable for *ETYS and NOA 2019* and *2020* stakeholder activities is shown below.**

**Figure 5.1**
*ETYS* and *NOA* stakeholder activities programme




We welcome your views on this year's *ETYS*, what works well and what we need to improve. Our stakeholder activities are a great way for us to:

- learn more about the views and opinions of all our stakeholders;
- provide constructive feedback and debate;
- create open, two-way communication about assumptions, analyses and findings; and
- let stakeholders know how we have used their feedback.

There are many ways you can let us have your feedback, including:

- taking part in our written *ETYS* consultation (planned for April 2020);
- consultation events as part of our customer seminars;
- industry engagement events e.g. operational forums, ENA meetings, etc;
- emails direct to **transmission.etys@nationalgrideso.com**; and
- stakeholder meetings.

# Chapter 6
## Further information

# Appendices overview

## Appendix A – System schematics and geographic drawings

Appendix A includes a set of system schematics and geographic drawings of the current NETS, with the approximate locations of existing power stations and reactive compensation plants shown. The schematics also show the NETS boundaries and *ETYS* zones we have used in our analysis.

You can view the system schematics and geographic drawings at: ETYS 2019 Appendix A

## Appendix B – System technical data

To allow modelling of the transmission network, basic network parameters such as connectivity and impedances are provided in Appendix B. The expected changes in the network based on the previous year's development decisions are also provided.

You can view the system technical data at: ETYS 2019 Appendix B

## Appendix C – Power flow diagrams

To demonstrate the impact of future changes on the transmission network, a set of winter peak power flow diagrams are presented in Appendix C. These show snapshots of present and future power flows along major circuit routes for the **Two Degrees** scenario. The expected changes in the network are based on the previous year's development decisions.

You can view the diagrams at: ETYS 2019 Appendix C

## Appendix D – Fault levels

Appendix D gives indications of fault levels calculated at two system conditions; at peak demand level and also at minimum demand levels for the current and future transmission network.

You can find out more at: ETYS 2019 Appendix D - Narrative

You can view the fault level data at peak demand: ETYS 2019 Appendix D - Peak

You can view the fault level data at minimum demand: ETYS 2019 Appendix D - Minimum

# Appendix E – *FES* charts and workbook

This appendix contains data and charts relating to national and/or regional National Electricity Transmission System (NETS) information about:

- energy storage and interconnectors
- summer minimum demand
- embedded generation.

You can find the regional modelling narrative at: http://fes.nationalgrid.com/media/1374/regionalmodelling.pdf

You can find the transmission level data at: ETYS 2019 Appendix E

You can find the distribution level data at: http://fes.nationalgrid.com/media/1412/fes-2019-electricity-regional-breakdown.xlsb

# Appendix H – Further information on inputs and methodologies

This appendix explains how the *FES* generation, demand and interconnector data is applied to the network simulation models. Please note that Appendices F and G which contain week 24 generation and demand data are no longer published within *ETYS* and have moved to the Transmission Network Use of System (TNUoS)[1] page under tools and calculations.

You can find out more at: ETYS 2019 Appendix H

# Appendix I – Transmission losses

Appendix I provides information on the drivers that may impact the total volume of future transmission losses on the NETS.

You can find out more at: ETYS 2019 Appendix I

[1] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges

# Meet the *ETYS* team

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## Network Development

In addition to publishing the *ETYS,* we are responsible, together with the transmission licence holders, for developing a holistic strategy for the NETS. This includes performing the following key activities:

- The management and implementation of the *Network Options Assessment (NOA)* process in order to assess the need to progress wider transmission system reinforcements.
- Producing recommendations on preferred options for NETS investment under the ITPR arrangements and publishing results annually in the *NOA* report.

You can contact us to discuss:

**Network requirements and *Electricity Ten Year Statement***

**James Whiteford**
GB System Capability Manager
James.Whiteford@nationalgrideso.com

**Cost-benefit analysis and *Network Options Assessment***

**Hannah Kirk-Wilson**
Technical and Economic Assessment Manager
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## Network Operability and Data and Modelling

In our Network Operability department, we are responsible for studying a variety of power system issues including generator and HVDC compliance. We develop and produce the *System Operability Framework* publications. From our Data and Modelling department we produce power system models and datasets for network analysis. We also manage the technical aspects of the GB and European electricity frameworks, codes and standards that are applicable to network development.

**Contact details to discuss the network data used in *ETYS*:**

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# Supporting parties

Strategic network planning and producing the *ETYS* requires support and information from many people. Parties who provide support and information that makes our work possible include:

- the GB electricity Transmission Owners
- the SO Energy Insights team who provide us with FES
- our customers.

Don't forget you can email us with your views on *ETYS* at: **transmission.etys@nationalgrideso.com**

You can also email us to join our mailing list to receive *ETYS* email updates.

# Glossary

| Acronym | Word | Description |
|---|---|---|
| | Ancillary services | Services procured by a system operator to balance demand and supply and to ensure the security and quality of electricity supply across the transmission system. These services include reserve, frequency control and voltage control. In GB these are known as balancing services and each service has different parameters that a provider must meet. |
| ACS | Average cold spell | Average cold spell is defined as a particular combination of weather elements which gives rise to a level of winter peak demand which has a 50% chance of being exceeded as a result of weather variation alone. There are different definitions of ACS peak demand for different purposes. |
| | Boundary allowance | An allowance in MW to be added in whole or in part to transfers arising out of the NETS SQSS economy planned transfer condition to take some account of year-round variations in levels of generation and demand. This allowance is calculated by an empirical method described in Appendix F of the Security And Quality of Supply Standards (SQSS). |
| | Boundary transfer capacity | The maximum pre-fault power that the transmission system can carry from the region on one side of a boundary to the region on the other side of the boundary while ensuring acceptable transmission system operating conditions will exist following one of a range of different faults. |
| CBA | Cost-benefit analysis | A method of assessing the benefits of a given project in comparison to the costs. This tool can help to provide a comparative base for all projects to be considered. |
| CCS | Carbon capture and storage | Carbon capture and storage is a process by which the $CO_2$ produced in the combustion of fossil fuels is captured, transported to a storage location and isolated from the atmosphere. Carbon capture and storage can be applied to large emission sources like power plants used for electricity generation and industrial processes. The $CO_2$ is then compressed and transported for long-term storage in geological formations or for use in industrial processes. |
| | Climate change targets | Targets for share of energy use sourced from renewable sources. The 2020 UK targets are defined in the Directive 2009/28/EC of the European Parliament and of the Council of the European Union, see **http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0028&from=EN#ntc1-L_2009140EN.01004601-E0001** |
| CCGT | Combined cycle gas turbine | Gas turbine that uses the combustion of natural gas or diesel to drive a gas turbine generator to generate electricity. The residual heat from this process is used to produce steam in a heat recovery boiler which, in turn, drives a steam turbine generator to generate more electricity. |
| CHP | Combined heat and power | A system whereby both heat and electricity are generated simultaneously as part of one process. Covers a range of technologies that achieve this. |
| CR | Community Renewables | This scenario achieves the 2050 decarbonisation target in a decentralised energy landscape. |
| CE | Consumer Evolution | This scenario makes progress towards decarbonisation through decentralisation, but does not achieve the 2050 target. |
| | Contracted generation | A term used to reference any generator who has entered into a contract to connect with the National Electricity Transmission System (NETS) on a given date while having a transmission entry capacity (TEC) figure as a requirement of said contract. |
| | Deterministic | A deterministic system is a system in which no randomness is involved in the development of future states of the system. |
| | Double-circuit overhead line | In the case of the onshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span in SHE Transmission's system or NGET's transmission system or for at least two miles in SP Transmission's system. In the case of an offshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span. |

| Acronym | Word | Description |
|---|---|---|
| DC | Direct current | An electric current flowing in one direction only. |
| DSR | Demand side response | A deliberate change to an industrial and commercial user's natural pattern of metered electricity or gas consumption, brought about by a signal from another party. |
| DNO | Distribution Network Operator | Distribution Network Operators own and operate electricity distribution networks. |
| | Embedded generation | Power generating stations/units that don't have a contractual agreement with the Electricity System Operator (ESO). They reduce electricity demand on the National Electricity Transmission System. |
| ENTSO-E | European Network of Transmission System Operators – Electricity | ENTSO-E is an association of European electricity TSOs. ENTSO-E was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising electricity markets in the EU. |
| ESO | Electricity System Operator | An entity entrusted with transporting electric energy on a regional or national level, using fixed infrastructure. Unlike a TO, the ESO may not necessarily own the assets concerned. For example, National Grid ESO operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power Transmission. |
| EU | European Union | A political and economic union of 28 member states that are located primarily in Europe. |
| FACTS | Flexible alternating current transmission system | FACTS devices are static power-electronic devices that utilise series and/or shunt compensation. They are installed in AC transmission networks to increase power transfer capability, stability, and controllability of the networks. |
| FES | Future energy scenarios | The FES is a range of credible futures which has been developed in conjunction with the energy industry. They are a set of scenarios covering the period from now to 2050, and are used to frame discussions and perform stress tests. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions. |
| GEP | Grid entry point | A point at which a generating unit directly connects to the National Electricity Transmission System. The default point of connection is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, or equivalent point as may be determined by the relevant transmission licensees for new types of substation. When offshore, the GEP is defined as the low voltage busbar on the platform substation. |
| GSP | Grid supply point | A point of supply from the GB transmission system to a distribution network or transmission-connected load. Typically only large industrial loads are directly connected to the transmission system. |
| *GTYS* | *Gas Ten Year Statement* | The GTYS illustrates the potential future development of the (gas) National Transmission System (NTS) over a ten year period and is published on an annual basis. |
| GW | Gigawatt | 1,000,000,000 Watts, a measure of power. |
| GWh | Gigawatt hour | 1,000,000,000 Watt hours, a unit of energy. |
| GB | Great Britain | A geographical, social and economic grouping of countries that contains England, Scotland and Wales. |
| HVAC | High voltage alternating current | Electric power transmission in which the voltage varies in a sinusoidal fashion, resulting in a current flow that periodically reverses direction. HVAC is presently the most common form of electricity transmission and distribution, since it allows the voltage level to be raised or lowered using a transformer. |
| HVDC | High voltage direct current | The transmission of power using continuous voltage and current as opposed to alternating current. HVDC is commonly used for point to point long-distance and/or subsea connections. HVDC offers various advantages over HVAC transmission, but requires the use of costly power electronic converters at each end to change the voltage level and convert it to/from AC. |
| | Interconnector | Electricity interconnectors are transmission assets that connect the GB market to Europe and allow suppliers to trade electricity between markets. |
| LCPD | Large Combustion Plant Directive | The Large Combustion Plant Directive is a European Union directive which introduced measures to control the emissions of sulphur dioxide, oxides of nitrogen and dust from large combustion plant. |
| | Load factor | The average power output divided by the peak power output over a period of time. |

# Glossary

| Acronym | Word | Description |
|---|---|---|
| | Marine technologies | Tidal streams, tidal lagoons and energy from wave technologies (see **http://www.emec.org.uk/**). |
| MW | Megawatt | 1,000,000 Watts, a measure of power. |
| MWh | Megawatt hour | 1,000,000 Watt hours, a measure of power usage or consumption in 1 hour. |
| | Merit order | An ordered list of generators, sorted by the marginal cost of generation. |
| MITS | Main Interconnected Transmission System | This comprises all the 400kV and 275kV elements of the onshore transmission system and, in Scotland, the 132kV elements of the onshore transmission system operated in parallel with the supergrid, and any elements of an offshore transmission system operated in parallel with the supergrid, but excludes generation circuits, transformer connections to lower voltage systems, external interconnections between the onshore transmission system and external systems, and any offshore transmission systems radially connected to the onshore transmission system via single interface points. |
| NETS | National Electricity Transmission System | The National Electricity Transmission System comprises the onshore and offshore transmission systems of England, Wales and Scotland. It transmits high-voltage electricity from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single Electricity System Operator (ESO). |
| NETS SQSS | National Electricity Transmission System Security and Quality of Supply Standards | A set of standards used in the planning and operation of the National Electricity Transmission System of Great Britain. For the avoidance of doubt, the National Electricity Transmission System is made up of both the onshore transmission system and the offshore transmission systems. |
| NGET | National Grid Electricity Transmission plc | National Grid Electricity Transmission plc (No. 2366977) whose registered office is 1-3 Strand, London, WC2N 5EH. |
| | Network access | Maintenance and system access is typically undertaken during the spring, summer and autumn seasons when the system is less heavily loaded and access is favourable. With circuits and equipment unavailable, the integrity of the system is reduced. The planning of system access is carefully controlled to ensure system security is maintained. |
| *NOA* | *Network Options Assessment* | The *NOA* is the process for assessing options for reinforcing the National Electricity Transmission System (NETS) to meet the requirements that the Electricity System Operator (ESO) finds from its analysis of the *Future Energy Scenarios (FES)*. |
| OFGEM | Office of Gas and Electricity Markets | The UK's independent National Regulatory Authority, a non-ministerial government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers. |
| | Offshore | This term means wholly or partly in offshore waters. |
| | Offshore transmission circuit | Part of an offshore transmission system between two or more circuit breakers which includes, for example, transformers, reactors, cables, overhead lines and DC converters but excludes busbars and onshore transmission circuits. |
| | Onshore | This term refers to assets that are wholly on land. |
| | Onshore transmission circuit | Part of the onshore transmission system between two or more circuit breakers which includes, for example, transformers, reactors, cables and overhead lines but excludes busbars, generation circuits and offshore transmission circuits. |
| OCGT | Open cycle gas turbine | Gas turbines in which air is first compressed in the compressor element before fuel is injected and burned in the combustor. |

| Acronym | Word | Description |
|---|---|---|
| | Peak demand | The maximum power demand in any one fiscal year: Peak demand typically occurs at around 5:30pm on a week-day between December and February. Different definitions of peak demand are used for different purposes. |
| PA | Per annum | per year. |
| PV | Photovoltaic | A method of converting solar energy into direct current electricity using semi-conducting materials. |
| | Planned transfer | A term to describe a point at which demand is set to the National Peak when analysing boundary capability. |
| | Power supply background (aka generation background) | The sources of generation across Great Britain to meet the power demand. |
| | Probabilistic | Model or approach where there are multiple possible outcomes, each having varying degrees of certainty or uncertainty of occurrence. This is based on the idea that you cannot be certain about results or future events but you can judge whether or not they are likely, and act on the basis of this judgment. |
| QB | Quadrature booster | A quadrature booster is a type of transformer also known as a phase shifting transformer and it is used to control the amount of real power flow between two parallel lines. |
| | Ranking order | A list of generators sorted in order of likelihood of operation at time of winter peak and used by the NETS SQSS. |
| | Reactive power | Reactive power is a concept used by engineers to describe the background energy movement in an alternating current (AC) system arising from the production of electric and magnetic fields. These fields store energy which changes through each AC cycle. Devices which store energy by virtue of a magnetic field produced by a flow of current are said to absorb reactive power; those which store energy by virtue of electric fields are said to generate reactive power. |
| | Real power | This term (sometimes referred to as "Active Power") provides the useful energy to a load. In an AC system, real power is accompanied by reactive power for any power factor other than 1. |
| | Seasonal circuit ratings | The current carrying capability of circuits. Typically, this reduces during the warmer seasons as the circuits' capability to dissipate heat is reduced. The rating of a typical 400kV overhead line may be 20% less in the summer than in winter. |
| | SHE Transmission | Scottish Hydro-Electric Transmission (No.SC213461) whose registered office is situated at Inveralmond HS, 200 Dunkeld Road, Perth, Perthshire PH1 3AQ. |
| SP | Steady Progression | This scenario makes progress towards decarbonisation through a centralised pathway, but does not achieve the 2050 target. |
| | SP Transmission | Scottish Power Transmission Limited (No. SC189126) whose registered office is situated at Ochil House, 10 Technology Avenue, Blantyre G72 0HT. |
| | Summer minimum | The minimum power demand of the transmission network in any one fiscal year. Minimum demand typically occurs at around 06:00am on a Sunday between May and September. |
| | Supergrid | That part of the National Electricity Transmission System operated at a nominal voltage of 275kV and above. |
| SGT | Supergrid transformer | A term used to describe transformers on the NETS that operate in the 275–400kV range. |
| | Switchgear | The term used to describe components of a substation that can be used to carry out switching activities. This can include, but is not limited to, isolators/disconnectors and circuit breakers. |
| | System inertia | The property of the system that resists changes. This is provided largely by the rotating synchronous generator inertia that is a function of the rotor mass, diameter and speed of rotation. Low system inertia increases the risk of rapid system changes. |
| | System operability | The ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably. |
| SOF | System Operability Framework | The SOF identifies the challenges and opportunities which exist in the operation of future electricity networks and identifies measures to ensure the future operability. |

# Glossary

| Acronym | Word | Description |
|---|---|---|
| | System stability | With reduced power demand and a tendency for higher system voltages during the summer months, fewer generators will operate and those that do run could be at reduced power factor output. This condition has a tendency to reduce the dynamic stability of the NETS. Therefore network stability analysis is usually performed for summer minimum demand conditions as this represents the limiting period. |
| | Transmission circuit | This is either an onshore transmission circuit or an offshore transmission circuit. |
| TEC | Transmission entry capacity | The maximum amount of real power deliverable by a power station at its grid entry point (which can be either onshore or offshore). This will be the maximum power deliverable by all of the generating units within the power station, minus any auxiliary loads. |
| | Transmission losses | Power losses that are caused by the electrical resistance of the transmission system. |
| TO | Transmission Owners | A collective term used to describe the three transmission asset owners within Great Britain, namely National Grid Electricity Transmission, Scottish Hydro–Electric Transmission Limited and SP Transmission Limited. |
| TSO | Transmission System Operators | An entity entrusted with transporting energy in the form of natural gas or power on a regional or national level, using fixed infrastructure. |
| TD | Two Degrees | This scenario achieves the 2050 decarbonisation target with large–scale centralised solutions. |

# Disclaimer

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