The Great Grid Upgrade

Sea Link

Strategic Options Report

Version A

October 2023

nationalgrid

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Contents

Sea Link
Document control

Document Properties	
Organisation	Arup
Author	Joe Turner
Approved by	Mark Perry & Stephen Mart (National Grid)
Title	Strategic Options Report
Data Classification	Public

Version History

Date	Version	Status	Description / Changes
24/10/2023	A	FINAL	First Issue

Executive Summary

Purpose of this report

This Strategic Options Report is a technical report providing an overview description of the options that National Grid Electricity Transmission plc (National Grid) has identified and subsequently evaluated for reinforcement of the network in the South East and East Anglia regions.

The stages of National Grid's process based approach when transmission system works are identified that would require additional consents and/or permissions are shown below:

Figure A - Approach to consenting process

This report forms part of the initial 'Options identification and selection' stage.

This executive summary provides an overview of the contents of this report and highlights key areas relevant to this project and the consultation on it including:

- reasons why the transmission system in the South East and East Anglia regions need to change;
- a summary description of options for providing additional transmission system capability that we identified as strategic options;
- how National Grid identified and evaluated strategic options; and
- the options that we intend to take forward to the next stage in the process.

National Grid Electricity Transmission

National Grid is the owner of the transmission system in England and Wales and holds an electricity transmission licence permitting transmission ownership activities. Our transmission licence requires that we provide an efficient, economic, and co-ordinated transmission system in England and Wales.

National Grid, as the regulated provider of electricity transmission services in England and Wales, is regulated by the Office of Gas and Electricity Markets ('Ofgem'). Transmission services include maintaining reliable electricity supplies and offering to construct new transmission system assets for new connections to the National Electricity Transmission System ('NETS').

In accordance with transmission licence requirements, we ensure that the transmission system in England and Wales meets the requirements in respect of transmission system security and quality of service at all times. As part of this requirement, we must ensure that sufficient transmission system capability is provided to meet demand and generator customer requirements and wider transmission system needs that exist and/or are expected.

When planning changes to our transmission system, we must be efficient, co-ordinated and economical and have regard to the desirability of preserving amenity, in line with the duties under sections 9 and 38 of the Electricity Act.

The Electricity System Operator (ESO)

The Electricity System Operator (ESO) is a separate legal entity to National Grid, but as of 2023 is still part of the National Grid Group. The ESO facilitates several roles on behalf of the electricity industry, including making formal offers to applicants requesting connection to the NETS. The ESO also manages shortfalls in capacity by reducing power flows and constraining generation. This is achieved by paying generators to reduce their outputs, known as ‘constraint costs’ (i.e. payments). Ultimately, constraint costs are passed on to consumers and businesses through electricity bills.

The ESO also makes investment recommendations to transmission owners, including National Grid, through an annual network planning cycle and other periodic reviews. This indicates which areas of the transmission system require reinforcement. This includes:

- The Future Energy Scenarios (FES), which take a number of energy industry views as part of a consultation process and develop a set of possible energy growth scenarios;
- The Electricity Ten Year Statement (ETYS), which sets out the network performance and requirements for all transmission in Great Britain over the next 10 years; and
- The Network Options Assessment (NOA)**,** which takes account of the FES and ETYS and considers options for reinforcing the transmission system, where this is economically optimal in comparison to continuing to pay constraint cost to manage shortfalls in capacity.

The ESO published the Holistic Network Design (HND) report in July 2022, accompanied by a ‘NOA Refresh’ document. The HND sets out a single integrated transmission network design that supports the large-scale delivery of electricity generated from offshore wind, with the NOA Refresh indicating which options are ‘HND critical’.

Ofgem has subsequently published the Accelerated Strategic Transmission Investment (ASTI) decision, which aims to facilitate the achievement of Government targets by streamlining the regulatory approval for the HND critical projects.

The need case

Consistent with the Government's Net Zero target, there has been, and continues to be, growth in the volume of renewable and zero carbon generation that is seeking to connect to the electricity transmission system in the East Anglia and South East regions. UK Government policy clearly sets out the critical requirement for significant reinforcement of the transmission system to facilitate the connection of renewable energy sources and to transport electricity to where it is used. In particular, the British Energy Security Strategy sets targets for the connection of up to 50 GW of offshore wind by 2030 as a key part of a strategy for secure, clean and affordable British energy for the long term.

System planning methodology

The concept of 'boundary capacity and capability' plays an important role in system planning. A boundary notionally splits the system into two parts, crossing critical circuit paths that carry power between the areas where power flow limitations may be encountered. Where 'boundary capacity' – the capacity of the circuit(s) across the boundary – is exceeded, we must resolve the capacity shortfall. The standards against which we assess these shortfalls are set out in the NETS System Security and Quality of Supply Standard (SQSS).

Also relevant are 'generation groups', which are groups of existing generating stations and/or proposed generating stations connecting in a particular geographical area of the transmission system. These are considered when assessing the network for compliance with the generation connection criteria of the NETS SQSS.

The relevant boundaries in East Anglia and the South East are EC3, EC5N, EC5, LE1 and SC2. The relevant Generation Groups are Sizewell (also sometimes referred to by the ESO as 'EC6') and Essex coast. These are illustrated in the network diagram in Figure B below. This figure includes the proposed Bramford to Twinstead project, for which development consent was sought from the Secretary of State in April 2023.

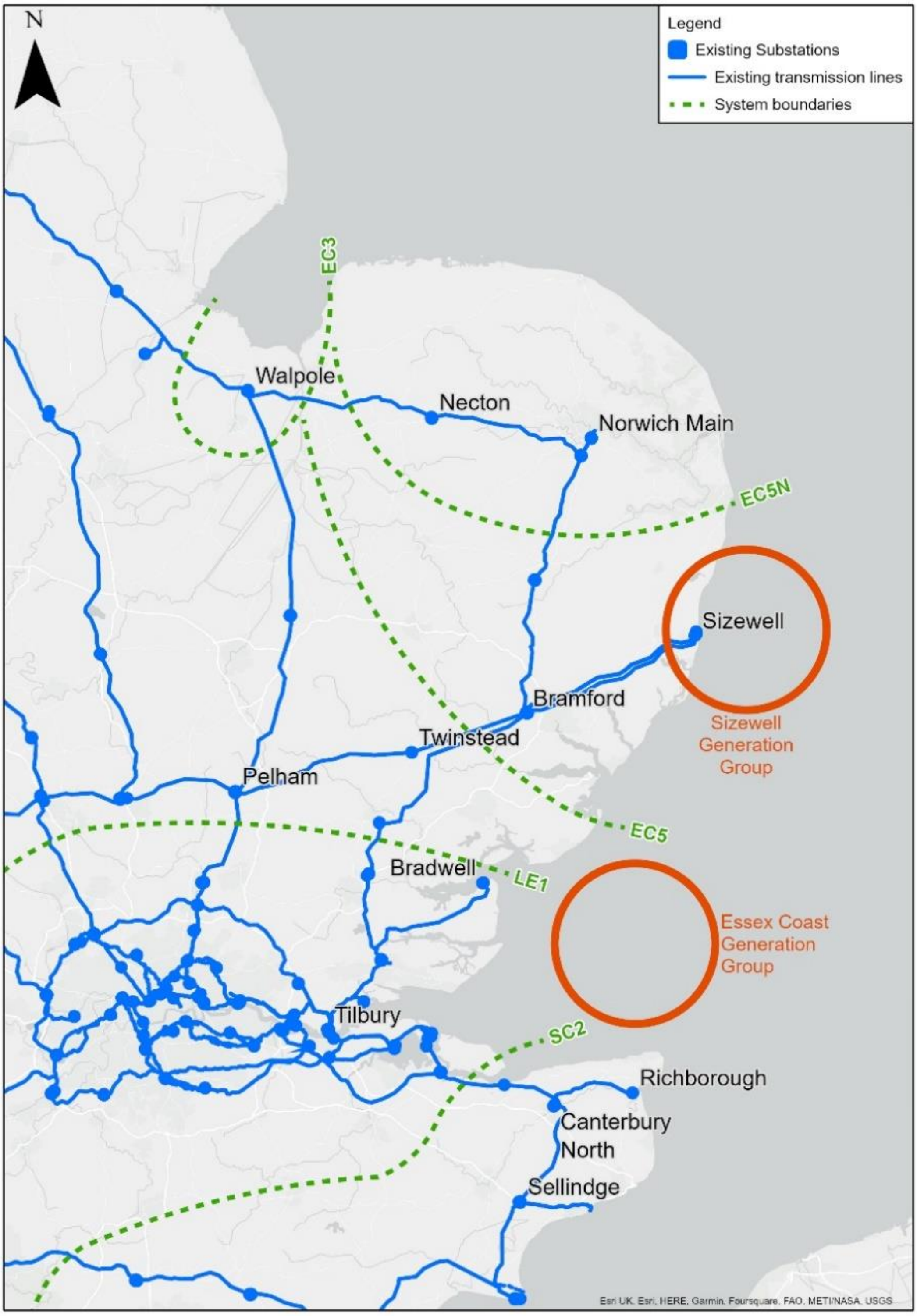
The network in East Anglia

The transmission system in East Anglia was built primarily to serve consumer demand from homes and businesses in the region. For many years the only significant power stations generating in the East Anglia region were the Sizewell A and the Sizewell B nuclear power stations, Spalding North and Sutton Bridge gas fired power stations, and some further smaller 132 kV connected gas fired power stations.

This generation capacity has recently been increased due to several offshore windfarms, with the existing generation in East Anglia (within Boundary EC5) totalling 7,687.4 MW of installed capacity. This is expected to grow substantially in coming years. In the East Anglia region, connection agreements have been signed for 20,310.1 MW of new installed capacity. These future connection agreements comprise a large volume of offshore wind generation (including East Anglia Offshore Wind), gas-fired generation, energy storage projects, a nuclear power station (at Sizewell C) and 3,100 MW of interconnector capacity.

Peak demand by 2029/30 in the East Anglia area is anticipated to be approximately 1,767 MW (total for demand substations of Walpole, Norwich Main and Bramford and with only minor demand being consumed at Sizewell). This means that generation in the area will significantly exceed local demand.

Figure B - East Anglia and South-East region transmission system and system boundaries



National Grid also has contracted connections for new generation and interconnectors located off the Essex Coast with proposed connections between the EC5 boundary and the LE1 boundary. The 3 proposed connections are as follows: -

- Tarchon Energy Limited Interconnector (1,500 MW By 2030)
- North Falls offshore Windfarm (1,000 MW by 2030)
- Five Estuaries Offshore Windfarm (1,080 MW by 2030)

These connections are proposed to be made to the network at a location which can accommodate the combined 3580 MW of generation. This requires a minimum of 3 transmission circuits to connect the generation to meet the minimum loss of infeed requirements of the NETS SQSS.

The network in the South East

The wider South East area is made up of the 400 kV and 275 kV network, which connects generation and demand in the major towns and cities of the wider South East and Midlands regions. The need to reinforce the network in the South East of England is driven by the interconnection with mainland Europe. The increase in interconnector capacity between Britain and continental Europe is likely to substantially increase the duration and magnitude of power exported from Britain during periods of high wind generation and imported from continental Europe during periods of low wind generation, requiring power to be supplied to and from the interconnectors located along the south and east coasts of England.

Existing installed capacity within the SC2 boundary totals 6,200 MW, including 4,020 GW of interconnectors. This total is anticipated to grow to 9,448.5 MW by 2031, including a further 700 MW of interconnection. Peak demand by 2029/30 within the SC2 boundary area is anticipated to be approximately 1,456 MW. Again, this means that generation (and interconnection) in the area will significantly exceed local demand.

System studies

The substantial increase in generator-driven power flows out of East Anglia including the Sizewell Generation Group and the requirement for generation export from Kent under high import conditions requires management with a single solution, allowing power flows to move in either direction to resolve the 2000MW shortfall in each area. During high generation outputs from the Sizewell Generation Group, during a fault 2000MW can be transported to Kent preventing overloads in East Anglia. Vice versa, during high interconnector import to Kent, during a fault 2000MW can be transported to the Sizewell Generation area preventing overloads in Kent. Therefore a single solution with full power flow control uniquely satisfies both the need in Sizewell Generation Group and Kent SC2 boundary.

Without reinforcement, the existing network is insufficient to accommodate the connection of the proposed new power sources. The ‘Thermal Boundary Export Limit’ – the physical maximum energy capacity the system can accommodate during planned system faults – would be exceeded, preventing export of power from each area experiencing the fault and causing significant overloads. In these circumstances, generators connecting in the area would be required to reduce their output and would be compensated via a ‘constraint’ payment. These costs would be passed on to end consumers. ESO analysis shows that, in this case, predicted constraint costs are likely to significantly exceed those of reinforcement.

We have assessed the possible impacts associated with the connection of the total volume of new generation on the affected boundaries. We are required to assess power flows between regions of the transmission system at Average Cold Spell Peak Demand (known as ‘Planned Transfers’). Studies show the Planned Transfer required in 2031 in East Anglia (EC5) would be between 16,126.1 MW and 20,664.2 MW export. This is presented as a range given that the contribution of fossil fuel-based generators will gradually reduce as renewable sources are connected – the top of the range assuming maximum availability of gas turbine generation, and the bottom of the range assumes no contribution from fossil fuelled stations such as gas fired stations. Both the maximum and minimum forecast planned transfers are significant increases on the existing Planned Transfer export condition of 4,573.3 MW and the NETS SQSS requires us to design to the higher of these conditions.

For the SC2 Boundary group in the South East, the Planned Transfer required by 2031, excluding existing nuclear and gas turbines (CCGT), is 6,574 MW. This is in excess of both the capability and capacity of SC2 and would cause both overloads and voltage stability issues on the south coast. There will be 4,720 MW of interconnectors in this region along with 4,728 MW of renewable generation and storage. This leaves the remaining double circuit with 4,500 MW capability and 5,873 MW of capacity and planned transfer of 6,574 MW leaving a deficit of between 701 and 2,074 MW.

This requires the SC2 boundary to be reinforced for this condition. Whilst provision of additional voltage support can increase circuit capability by circa 300 MW, this would require 1,800MW of capacity from the SC2 area.

Studies show that there are significant boundary deficits across these boundaries. There are five distinct issues that need to be resolved by system reinforcement:

- Provision of 8,084 MW of capacity across East Anglia EC5 Boundary and 3,492 MW of capacity across EC5N Boundary.
- Provision of 7,576 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,580 MW of connection capacity for the Essex Coast Generation Group.
- Provision of 1,800 MW of capacity across the SC2 Boundary.

Summary of need case

In summary, this analysis shows that without reinforcement, the capacity of the existing network in East Anglia and the South East is insufficient to accommodate the connection of proposed new power sources connecting in the area. This need is emphasised by the analysis of the ESO, which has recommended ‘proceed’ signals in the NOA for several reinforcements in the East Anglia and South East region, including new 400 kV circuits in north and south East Anglia and a new Offshore High Voltage Direct Current (HVDC) link between Suffolk and Kent. The July 2022 NOA Refresh also identified reinforcements in this area as HND essential options, meaning that it considers them as essential to meet the UK Government’s 2030 offshore wind targets.

We have therefore been assessing the reinforcement options available for providing the additional capability required.

Initial strategic options analysis

The resolution of the need case is dependent on solutions providing additional capability in both East Anglia and the South East (boundaries EC5, EC5N, LE1 and SC2 and Sizewell Generation Group and Essex Coast Generation Group). Reinforcements in East Anglia are being separately progressed, with the current preference being the Norwich to Tilbury reinforcement. This report considers options for providing additional capacity between East Anglia and the South East only and assumes that Norwich to Tilbury, or a variant of equivalent capability, is also progressed. A reinforcement between Bramford and Twinstead is also considered necessary, with development consent having been sought for this reinforcement in April 2023.

A new offshore HVDC link between South East of England and East Anglia reinforcement was first assessed in the 2018/2019 NOA. This option crossed multiple system boundaries, and was included for comparison with other options that only addressed the need in the South East of England. The 2018/2019 NOA recommended a ‘proceed’ signal for this option. Strategic options were then developed that explored alternative HVDC links that could provide the reinforcement required. This work identified that a connection between East Anglia and Richborough in Kent provided this reinforcement, this was then reflected in the subsequent 2019/2020 NOA. As shown within this report, solutions which resolve capacity requirements of the Sizewell Generation Group and SC2 Kent boundary are the only options that satisfy the needs case.

Additional network studies in East Anglia were undertaken to confirm which connection point provided the best value to customers whilst minimising potential environmental and socio-economic impacts. These studies identified that the HVDC Link needed to connect into the Sizewell area in order to meet the needs of the Sizewell Generation Group, which would require additional infrastructure if the capacity provided by the 2GW HVDC link were not connected to the group. .

The analysis was published in October 2022 in the Corridor and Preliminary Routeing and Siting Study (CPRSS). This identified four strategic options to address the need:

- SL1 – Sizewell Area to Sellindge subsea – approx. 180 km
- SL2 – Sizewell Area to Richborough subsea approx. 120 km
- SL3 – Sizewell Area to Canterbury subsea approx. 120 km
- LL 1 – Sizewell Area to Canterbury onshore approx. 220 km

To enable power transfer from the Sizewell Generation Group, it is necessary for all options to have a northern connection point in the Sizewell area.

For each of the strategic options, we considered the technology options available for transmission system reinforcement, environmental and socio-economic constraints, lifetime costs of each technology option, as well as initial capital cost. Two technology options were considered for the offshore options: AC Subsea cable and HVDC Subsea cable. Four technology options were considered for the onshore option: overhead line (OHL), underground cables, Gas Insulated Lines (GIL) and onshore HVDC. These options are shown in Figure C below.

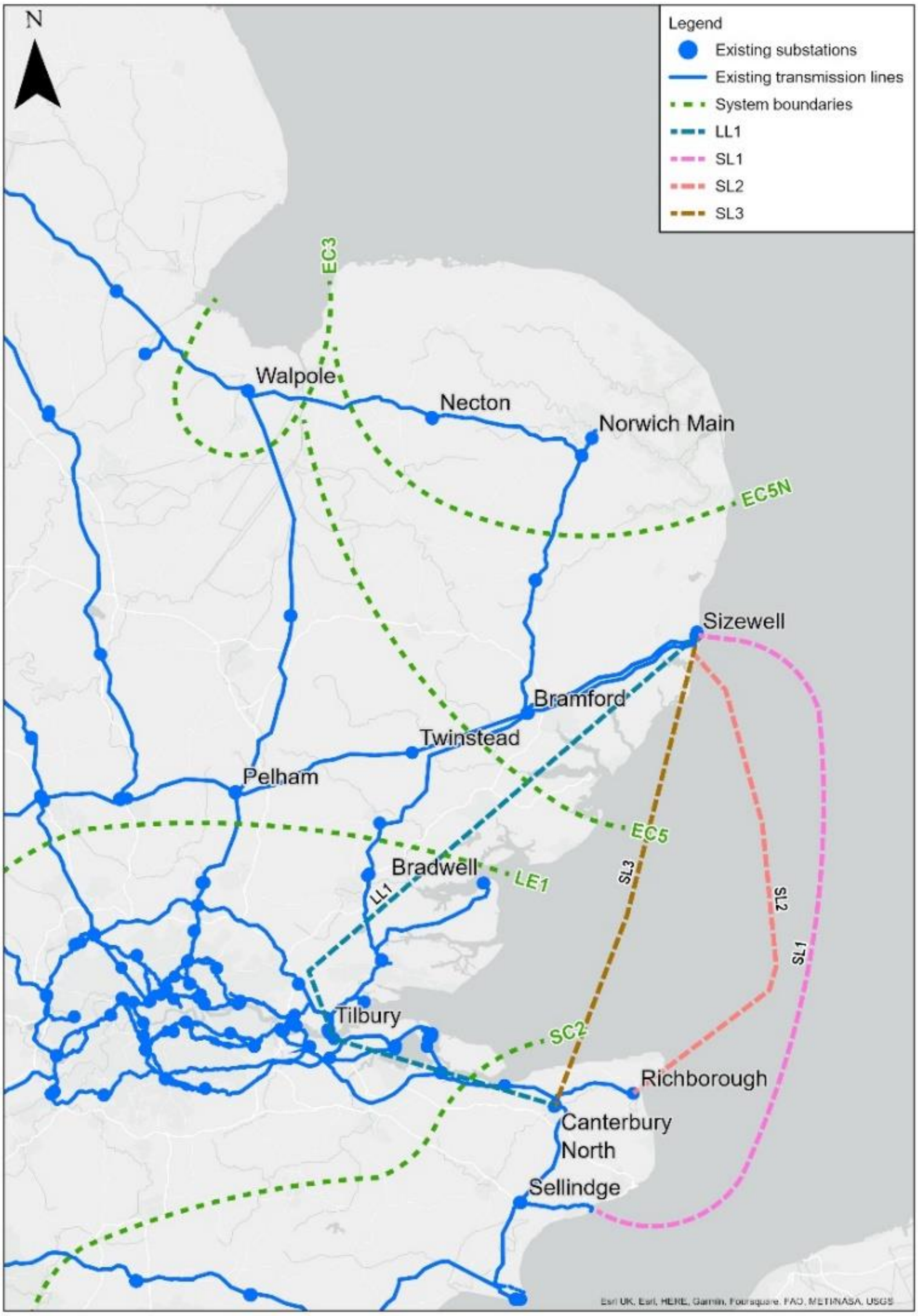
Onshore option LL1 (Sizewell to Canterbury) would be lowest capital cost connection, but with a higher lifetime cost than offshore HVDC solutions. This option would be subject to increased costs for crossing of the River Thames (likely by tunnel) and for any underground cable sections. This option was also found not to pass the technical and benefits filters in our options appraisal methodology, and therefore this option was not carried forward for environmental and socio-economic evaluation.

None of the environmental and socio-economic impacts of the remaining (offshore) options SL1, SL2 and SL3 were considered to present in-principle issues that could not be mitigated with careful consideration of routeing and use of appropriate technologies to specific constraints, as is consistent with the existing and emerging National Policy Statements (NPSs) against which proposals for nationally significant infrastructure projects are assessed.

The lowest cost subsea option is equal between option SL2 and SL3, a connection from Sizewell Area to Richborough or Canterbury over a distance of 145 km utilising a 2000 MW Voltage Source Converter (VSC) HVDC connection.

From an environmental and socio-economic perspective SL2 was preferred to SL3 due to the marine constraints off the north Kent coast and onshore siting opportunities close to Richborough substation. As such the CPRSS concluded that SL2 was the option that would best balance overall technical, cost, environmental and socio-economic considerations.

Figure C – Options considered



Strategic options assessment

In line with Our Approach to Consenting, this Strategic Options Report is designed to test the assumptions and interim conclusions made to date based on the latest information available. This report reviews the conclusions of the Strategic Options section (Section 2) of the CPRSS, as summarised above.

This report backchecks and reviews the options (SL1, SL2, SL3 and LL1) identified in the CPRSS. This is considered to be a robust range of credible options. No other options have been identified since the CPRSS was completed. It remains necessary for all options to have a northern connection point in the Sizewell area to resolve the need case set out in Section 3.

Following technical and benefits filtering, the CPRSS excluded the onshore option LL1 from environmental and socio-economic appraisal. This strategic options assessment includes LL1 for completeness, to assess whether the option offers any benefit over the offshore options SL1, SL2 and SL3.

None of the environmental and socio-economic considerations identified appear to represent ‘in-principle’ issues that could not be addressed in accordance with the relevant policies set out in EN-1 and EN-5. Given the similarity in cost and technical terms between SL2 (Richborough) and SL3 (Canterbury) it is particularly relevant to make a comparison of environmental and socio-economic factors to differentiate between the options.

Taking all environmental and socio-economic factors into account, Richborough (SL2) is preferred over Canterbury (SL3). Sellindge (SL1) and the onshore option (LL1) would offer no benefit in environmental or socio-economic terms to justify the greater distance, and associated costs, required.

The costs for both onshore and offshore options included within this report have been updated to account for the latest information and are provided in a 2020/2021 price base. This report supersedes any information provided prior to October 2023.

Table A - Cost Summary of works required to meet project need

Boundary or Group	Offshore options			Onshore options	
Sizewell and SC2	**SL1 – Sizewell Area to Sellindge**	**SL2 – Sizewell Area to Richborough**	**SL3 – Sizewell Area to Canterbury**	**LL1 – Sizewell Area to Canterbury**	**LL1 – Sizewell Area to Canterbury**
Economic Technology (Capacity)	HVDC 180 km (2000 MW)	HVDC 120 km (2000 MW)	HVDC 120 km (2000 MW)	HVDC 220 km (2000 MW)	AC OHL 220 km (6380 MW)
Capital Cost including non-circuit works	£1,339.6m	£1,154.2m	£1,154.2m	£1,463.2m	£1,049.8m
Circuit 40yr Lifetime NPV Cost	£1,305m	£1,120m	£1,120m	£1,429m	£1,501m

Taking all of this into account, we propose at the current stage to take forward a preference for SL2 from Sizewell Area to Richborough over a distance of approximately 120 km utilising a

2000 MW VSC HVDC subsea connection. Alongside our interim preference in East Anglia for an overhead line between Norwich Main, Bramford and Tilbury, this would meet the urgent and critical need to increase capacity across boundaries EC3, EC5N, EC5, LE1 and SC2, as well as providing the required capacity for the Sizewell and Essex Coast Generation Groups. We will continue to review our work in light of changes in circumstances and we will have regard to consultation responses.

1. Introduction

1.1.1 This Strategic Options Report report has been prepared by National Grid Electricity Transmission plc (National Grid) as part of the ongoing strategic options assessment and decision-making process involved in promoting new transmission projects. It records how we have had regard to a range of considerations in developing those projects. This report has been prepared in accordance with 'Our Approach to Consenting'[1].

1.1.2 This report addresses the Sea Link (hereafter referred to as the 'Proposed Project') between the South East of England and East Anglia, but also includes information about wider reinforcements in the East Anglia area, which are interactive with the need case. The Proposed Project is described in greater detail later in this report. This consideration of strategic options is part of an iterative process in response to interaction of a range of emerging energy projects and customer requirements.

1.1.3 As we continue to develop our plans and as our proposals evolve, we keep strategic options under review, taking account of consultation feedback and any changes that might influence the assessment of technical, environmental, socio-economic and cost considerations.

1.1.4 As set out in Our Approach to Consenting there are 5 stages. This document forms part of the "Options identification and selection stage" and is at the very start of the process, as shown below. This report provides information about scheme development, to support non-statutory consultation.

Figure 1.1 – Approach to consenting process

1.1.5 The report is structured as follows:

- Background to England and Wales electricity transmission system (Section 2)
- Summary of the need case (Section 3)
- Identification of strategic options (Section 4)
- Options assessment process (Section 5)
- Strategic options overview (Section 6)
- Appraisal of strategic options (Sections 7-10)
- Strategic options appraisal conclusions (Section 11)

[1] Our Approach to Consenting, National Grid (April 2022) https://www.nationalgrid.com/electricity-transmission/document/142336/download

- Interaction with other projects (Section 12)
- Conclusions (Section 13)

1.1.6 This document is also supported by a detailed set of appendices setting out our obligations, technology assumptions and cost appraisal methodology as follows:

- Appendix A Summary of National Grid Electricity Transmission Legal Obligations
- Appendix B Requirement for Development Consent Order
- Appendix C Technology Overview
- Appendix D Economic Appraisal
- Appendix E Mathematical Principles used for AC Loss Calculation
- Appendix F Glossary of Terms and Acronyms
- Appendix G Appraisal study areas

1.1.7 This Strategic Options Report is part of an iterative process, investigating prospective opportunities and reassessing previous provisional conclusions.

2. Background to England and Wales electricity transmission system

2.1 Background

2.1.1 In 2019 the Committee on Climate Change (CCC) published its Net Zero report setting out recommendations to the UK Government on long-term emissions targets for the UK. The Government subsequently adopted the Climate Change Act 2008 (2050 Target Amendment) Order 2019, which increased its pledge to achieve 100% reduction in emissions by 2050. One of the ways this will be achieved is through decarbonisation, including moving away from fossil fuels providing energy to our homes and businesses. The vision for a transition to clean energy was set out in December 2020 with the publication of the Energy White Paper, which added further detail to the Prime Minister's Ten Point Plan for a Green Industrial Revolution. This requires the adoption of alternative sources of energy to power our homes, transport and businesses.

2.1.2 As a result, electricity production is now moving towards reducing greenhouse gas emissions, by increasing renewable and low carbon sources, such as offshore and onshore wind, solar energy and new nuclear generation. The National Infrastructure Commission (NIC) has published a report recommending to the UK Government that renewable generation can be increased to 65% of supply by 2030 at no adverse cost to consumers, enabling the decarbonisation in part of sectors such as transport and heating via electrification.

2.1.3 Following the publication of the NIC report, the UK Government published the British Energy Security Strategy[2] in April 2022 setting out a strategy for secure, clean and affordable British energy for the long term. This strategy sets out energy ambition across a number of sectors such as, including:

- Up to 8 Reactors of Nuclear energy being progressed reaching up to 24 GW to be achieved by 2050;
- Up to 50 GW of offshore wind connected by 2030 including 5 GW of which will be offshore floating wind;
- Up to 10 GW of low carbon hydrogen production capacity by 2030, doubling the previous ambition; and
- 600,000 heat pump installations a year by 2028 and improving housing stock insulation.

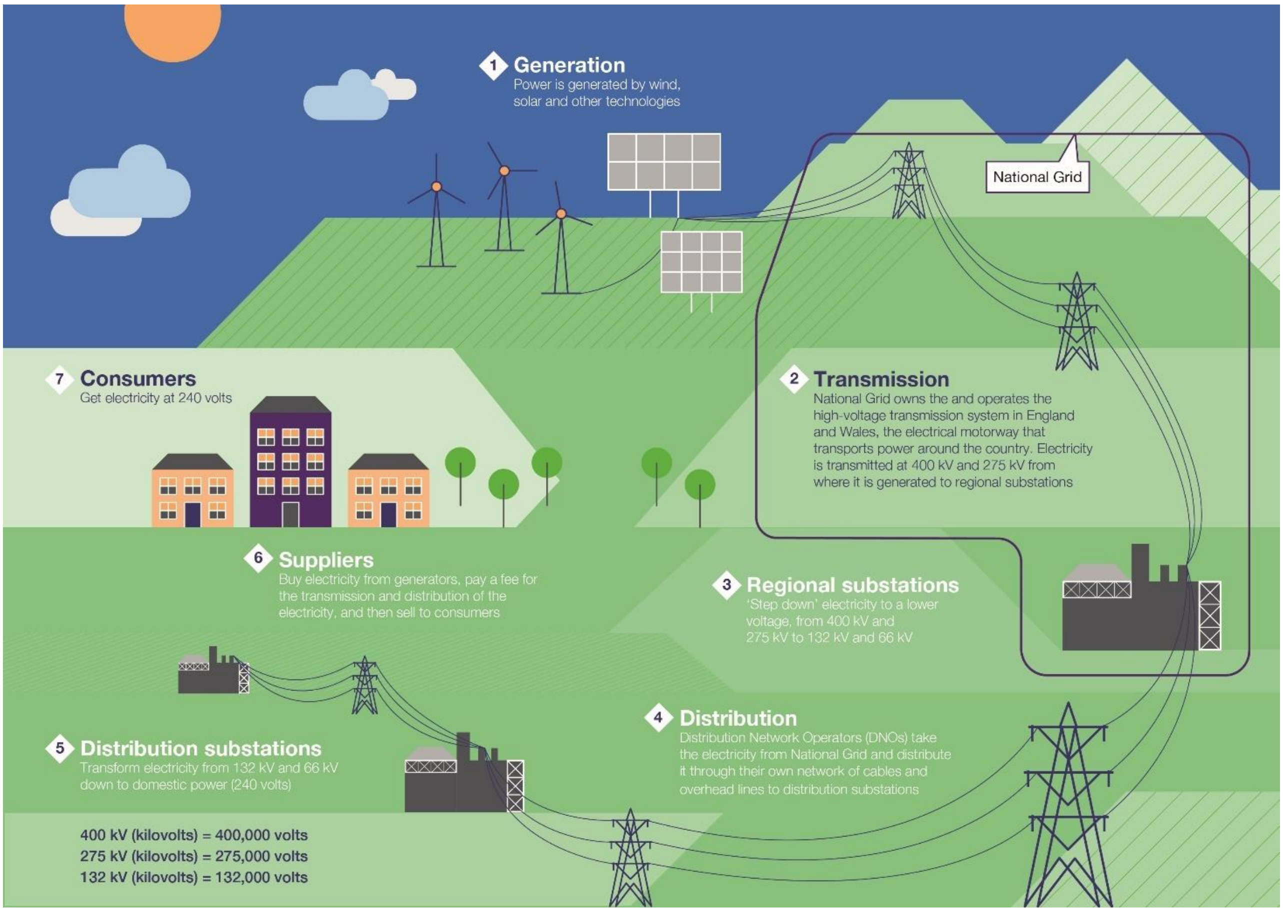
2.1.4 The Powering Up Britain paper was published in March 2023 by the UK Government. This document provides an update of the strategy for secure, clean and affordable British energy for the long term future, and closely relates to the points raised in Section 3.

2.1.5 To facilitate these ambitions, electricity network infrastructure is needed to ensure that energy can be transported from where it is generated to where it is used.

[2] British energy security strategy - GOV.UK (www.gov.uk)

2.1.6 The existing transmission system operates at 400 kV and 275 kV and transports bulk supplies of electricity from generating stations to demand centres. Distribution systems operate at 132 kV and below in England and Wales and are mainly used to transport electricity from bulk infeed points (interface points with the transmission system) to the majority of end customers. See Figure 2.1 below.

Figure 2.1 – The electricity system from generator to consumer



2.1.7 A single electricity market serves the whole of Great Britain. In this competitive wholesale market, generators and suppliers trade electricity on a half hourly basis. Generators produce electricity from a variety of energy sources, including coal, gas, nuclear and wind, and sell energy produced in the wholesale market. Suppliers purchase electricity in the wholesale market and supply to end customers.

2.1.8 Electricity can also be traded on the single market in Great Britain by generators and suppliers in other European countries. Interconnectors with transmission systems in France, Northern Ireland, Belgium, Denmark and the Netherlands are used to import electricity to and/or export electricity from the transmission system.

2.2 National Grid's role

2.2.1 National Grid Electricity Transmission plc (National Grid) is the owner of the high voltage transmission system in England and Wales and is part of the National Grid Group of companies.

2.2.2 Transmission of electricity in Great Britain requires permission by a licence granted under Section 6(1)(b) of the Electricity Act 19896 (as amended) (the Electricity Act). National Grid has been granted a transmission licence (the Transmission Licence) and is therefore bound by legal obligations, which are primarily set out in the Electricity Act and the Transmission Licence. In its role in providing transmission services in England and Wales, National Grid is regulated by the Office of Gas and Electricity Markets (‘Ofgem’).

2.2.3 National Grid’s legal obligations include duties under section 9, section 38 and Schedule 9 of the Electricity Act. In summary, these require us to:

- Develop and maintain an efficient, co-ordinated and economical system of electricity transmission;
- When formulating proposals for the installation of electric line or the execution of any other works for or in connection with the transmission or supply of electricity, have regard to the desirability of preserving natural beauty, of conserving flora, fauna and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and
- When formulating such proposals, do what it reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects.

2.2.4 The Electricity System Operator (ESO) is a separate legal entity to National Grid, but as of 2023 is still part of the National Grid Group. The ESO facilitates several roles on behalf of the electricity industry, including making formal offers to connection applicants to the National Electricity Transmission System (NETS).

2.2.5 National Grid is obligated to provide the physical connections to the elements of the NETS that National Grid own.

2.3 National Grid’s existing transmission system

2.3.1 The electricity transmission system is a means of transmitting electricity around the country from where it is generated to where it is needed. The existing transmission system was developed to transport electricity in bulk from power stations to demand centres. Much of the transmission system was originally constructed in the 1960s. Incremental changes to the transmission system have subsequently been made to meet increasing customer demand and to connect new power stations and interconnectors with other transmission systems.

2.3.2 National Grid's transmission system consists of approximately 7,200 km of overhead lines and a further 700 km of underground cabling, operating at 400 kV and 275 kV. In general, 400 kV circuits have a higher power carrying capability than 275 kV circuits. These overhead line and underground cable circuits connect around 340 substations forming a highly interconnected transmission system. Further details of the transmission system including geographic and schematic representations are published by the ESO annually as part of its Electricity Ten Year Statement (ETYS)[3].

2.3.3 The transmission system provides a connection between large generation stations and the connection of demand for homes and businesses in England and Wales. The

[3] Electricity Ten Year Statement, National Grid ESO (2022) https://www.nationalgrideso.com/document/275611/download

generation directly connected to the electricity transmission system tends to be of two types: low carbon energy (nuclear, wind farms, solar) and large thermal generation (gas powered generation and older fossil fuel powered generation). This is also supplemented by new storage technologies such as battery storage and hydro storage.

2.3.4 Circuits are those parts of the system used to connect between substations on the transmission system. The system is mostly composed of double-circuits (in the case of overhead lines carried on two sides of a single pylon) and single-circuits. Substations provide points of connection to the transmission system for power stations, distribution networks, transmission connected demand customers (e.g. large industrial customers) and interconnectors.

2.4 How the transmission system operates

2.4.1 A generation group consists of a number of existing generating stations and/or proposed generating stations connecting in a particular geographical area of the transmission system.

2.4.2 Proposed generating stations require a connection agreement with the ESO to authorise their connection to the transmission system. The relevant transmission owner must then assess the generation group to ensure that the transmission system is sufficient in the area to accommodate the existing and proposed generation. Upon completion of the assessment, the ESO will make a formal offer of connection.

2.4.3 The capacity of the transmission system is based on the physical ability of electrical circuits to carry power. Each circuit has a defined capacity and the total capacity of the circuits in a region or across a boundary is the sum of all of the capacity of all the circuits.

2.4.4 The capability of the transmission system is the natural flow of energy that can occur in the infrastructure comprising the network. Due to the physical properties of the transmission system, this is often not as great as the theoretical capacity of the infrastructure in question.

2.4.5 Where power flows are constrained by the transmission system across a specific number of circuits, this is termed a "boundary" by the ESO. Such boundaries are used in the ETYS to identify constraints which may require changes to the transmission system in the next 10 years.

2.4.6 Where capacity and capability of the transmission system are not sufficient, either from a generation group or across a boundary, National Grid will be required to reinforce the network. It does this by either modifying the existing network (if possible) and/or constructing additional transmission infrastructure to resolve the shortfall.

2.5 Requirement for changes to the transmission system

2.5.1 Under Section 9 of the Electricity Act 1989, National Grid is required to provide an efficient, co-ordinated, and economical transmission system in England and Wales. The transmission infrastructure needs to be capable of maintaining a minimum level of security of supply and of transporting electricity from and to customers. National Grid is required to ensure that its transmission system remains capable as customer requirements change.

2.5.2 The transmission system needs to cater for demand, generation and interconnector changes. Customers can apply to the independent ESO for new or modified connections to the transmission system. The ESO is required to respond to each customer application with an offer for a new or modified connection.

2.5.3 In line with the Government's 2050 targets, a large number of applications have been made to the ESO for connection at locations that are more remote from the existing transmission system, or which are in the vicinity of parts of the transmission system that do not have sufficient capacity available for the new connection.

2.5.4 National Grid has a key role providing a transmission system which serves all consumers in England and Wales. As a monopoly, we are regulated by the Office of Gas and Electricity Markets (Ofgem) on behalf of consumers and is required to operate in accordance with the Transmission Licence. This includes maintaining reliable electricity supplies and offering to connect new energy suppliers. Where the network needs to be developed to do that, we must be efficient, co-ordinated and economical and have regard to the desirability of preserving amenity, in line with the duties under sections 9 and 38 of the Electricity Act.

2.5.5 In developing new network infrastructure proposals, we are therefore guided by the legislative and policy framework set by the UK Government. Including requirements set out in the Planning Act 2008 and associated National Policy Statements as described in detail in Appendix B.

2.6 Electricity System Operator (ESO) role in development of the transmission system

2.6.1 The ESO has annual processes to publish the Electricity Ten Year Statement (ETYS), which sets out the network performance and requirements for all transmission in Great Britain over the next 10 years.

2.6.2 The ESO also has annual processes to publish the Future Energy Scenarios[4] (FES) which take a number of energy industry views as part of a consultation process and develop a set of possible energy growth scenarios.

2.6.3 Similarly, it has an annual process to publish the Network Options Assessment[5] (NOA), which considers options for reinforcing the transmission system and makes economic recommendations. This document takes account of the ETYS and FES to establish via a Cost Benefit Analysis (CBA) process when it is right to take forward options proposed by transmission owners to increase network capacity. This considers the capital costs of the proposal, delivery timescales and constraint costs (as explained further below) avoided by delivering the proposal. This establishes when a proposed reinforcement becomes the most economical, efficient, and coordinated way to deliver value to Great Britain's energy consumers.

2.6.4 The ESO manages shortfalls in boundary capacity by reducing power flows and constraining generation. This is achieved by paying generators to reduce their outputs,

[4] Future Energy Scenarios, National Grid ESO (2022) https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[5] Network Options Assessment 2021/22 Refresh, National Grid ESO (2022) https://www.nationalgrideso.com/document/262981/download

known as ‘constraint costs’. Ultimately, constraint costs are passed on to consumers and businesses through electricity bills.

2.6.5 The ESO published the Holistic Network Design[6] (HND) report in summer 2022. It is now engaged in the HND Follow Up Exercise. The HND sets out a single integrated transmission network design that supports the large-scale delivery of electricity generated from offshore wind.

2.6.6 The ESO is also undertaking the Offshore Co-ordination Project[7], of which the HND is part. This considers how the transmission network is designed and delivered, to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way considering the increased ambition for offshore wind to achieve net zero. It considers environmental, social and economic costs.

2.6.7 Subsequent to the ESO reinforcements identified in HND and NOA refresh, Ofgem has published the Accelerated Strategic Transmission Investment[8] (ASTI) decision, which aims to facilitate achieving government targets by streamlining the regulatory approval and funding process for ASTI projects.

2.7 National Statutory Duties (Electricity Act 1989)

2.7.1 National Grid has duties placed upon it by the Electricity Act 1989 ('the Electricity Act') and operates under the terms of its transmission licence. Those duties and terms of particular relevance to the development of the proposed connection described in this report are set out below. In the instances that National Grid is developing new infrastructure, it is required to have regard to these following statutory duties under the Electricity Act:

- Electricity Act 1989 – Schedule 9 (preservation of amenity including: taking into account impacts upon communities, landscape, visual amenity, cultural heritage and ecological resources).
- Section 38 and Schedule 9 of the Electricity Act 1989 state that: “(1) In formulating any relevant proposals, a licence holder or a person authorised by exemption to generate, distribute, supply or participate in the transmission of electricity:
  - shall have regard to the desirability of preserving natural beauty, of conserving flora, fauna and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and
  - shall do what he reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects.”

[6] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)

[7] Offshore Coordination Project | ESO (nationalgrideso.com)

[8] Decision on accelerating onshore electricity transmission investment | Ofgem

2.8 National Policy Statements (NPS) – EN1 (Overarching National Policy Statement for Energy) and EN5 (Electricity Networks Infrastructure)

2.8.1 National Policy Statements are produced by government and set out the UK Government's objectives for the development of nationally significant infrastructure. The extant National Policy Statements relevant to energy network infrastructure are EN-1 Overarching National Policy Statement for Energy, EN-3 National Policy Statement for Renewable Energy, and EN-5 National Policy Statement for Electricity Networks Infrastructure. These were published in 2011. Taken together they provide the primary basis for decisions on applications for electricity networks infrastructure which are classified as Nationally Significant Infrastructure Projects. Where relevant (e.g. in the case of the consideration of development in nationally designated landscapes) these are referred to in this Strategic Options Report.

2.8.2 In March 2023, the Government published draft revised versions of energy NPSs for consultation, including EN-1, EN-3 and EN-5. Where relevant, proposed revised text from these drafts is referred to in this report. A key theme in the draft suite of NPSs is the urgency of need for new transmission infrastructure to connect offshore wind to facilitate the Government's target of deploying up to 50 GW of offshore wind capacity by 2030. The 2023 revision of EN-3 confirms that "Government has concluded that there is a critical national priority (CNP) for the provision of nationally significant new offshore wind development and supporting onshore and offshore network infrastructure and related network reinforcements ("CNP Infrastructure")" (para. 3.8.12).

2.8.3 Paragraphs. 2.8.8 to 2.8.13 of the draft EN-3 sets out a policy presumption that, subject to any legal requirements, the urgent need for CNP Infrastructure to achieving energy objectives, together with the national security, economic, commercial, and net zero benefits, will in general outweigh any other residual impacts not capable of being addressed by application of the mitigation hierarchy". According to the Glossary in draft EN-1, "CNP Infrastructure is defined as nationally significant new offshore wind development and supporting onshore and offshore network infrastructure and related network reinforcements".

2.8.4 Paragraphs 1.1.3 to 1.1.4 of EN-5 reinforce that transmission infrastructure is included in the CNP Infrastructure definition:

The electricity network infrastructure to support the government's ambition is as important as the offshore wind generation infrastructure. Without the development of the necessary networks to carry offshore wind power to where it is needed in the UK, the offshore wind ambition cannot be achieved.

As identified in EN-3, offshore wind development, and the supporting onshore and offshore transmission infrastructure and related network reinforcements, are viewed by the government as being a critical national priority (CNP) and should be progressed as quickly as possible.

3. Need case

3.1 Background

3.1.1 The electricity industry in Great Britain is undergoing unprecedented change. Closure of fossil fuel burning generation and end of life nuclear power stations means significant additional investment in new generating and interconnection capacity will be needed to ensure existing minimum standards of security and supply are maintained.

3.1.2 Growth in offshore wind generation and interconnectors to Europe has seen a significant number of connections planned in Scotland, England and significantly in areas of the East Coast of England, including in East Anglia and the South East.

3.1.3 The Climate Change Act 2008 (as amended) now commits the UK Government by law to reducing greenhouse gas emissions by at least 100% from the 1990 baseline by 2050, strengthening the likelihood of most of these connections progressing to delivery. This 2050 target is commonly known as 'Net Zero'.

3.1.4 To achieve Net Zero, there will need to be a substantial shift away from the use of fossil fuel burning generation. This has led to investment in offshore wind generation, which will increase further in the future.

3.1.5 Historically, the transmission system was powered by coal powered generating stations. The increasing importance of low carbon generation has driven the closure of these generating stations, with more expected to close in the future. This generating capacity is being replaced by low carbon generation which is geographically located away from the coal powered generating stations. The transmission system must be updated to reflect the location of the generating stations.

3.1.6 Electricity demand is especially concentrated in large urban areas, including urban areas in the M62 corridor, the M18 corridor, the Midlands, the M4 corridor and the Southeast. The transmission system carries bulk energy from the generators to points on the network where that power is taken onto the distribution networks for onward transmission to homes and businesses across England and Wales. As the country decarbonises, this demand for energy will increase and replace fossil fuel usage.

3.2 National Electricity Transmission System Security and Quality of Supply Standard

3.2.1 National Grid must comply with Section 9 of the Electricity Act and Standard Condition D3 (Transmission system security standard and quality of service) of its Transmission Licence. This means that where the boundary capacity of the Main Interconnected Transmission System (MITS) is exceeded against the standards, National Grid must resolve the capacity shortfall under the terms of its Transmission Licence. The standards against which National Grid assesses these shortfalls are set out in the "Design of the Main Interconnected Transmission System" section of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS).

3.2.2 The NETS SQSS also sets out in "Generation Connection Criteria applicable to the onshore transmission system" that connections to the transmission system must be secured to meet the identified requirements. Where the NETS SQSS applies, the generator(s) are considered part of a "generation group" for assessment against these criteria.

3.2.3 Generators apply to National Grid ESO for connections to the NETS in Great Britain. If the application is for an onshore generation connection, the applicant will indicate the specific location of the generating station, which will indicate the likely geographical connection to the transmission system. If the application is for an offshore connection or impacts multiple transmission owners, the ESO will coordinate the process known as CION/HND to determine the preferred connection option.

3.2.4 The ESO ensures the relevant on shore or offshore transmission owner undertakes generation connection process studies via the relevant process and makes a connection offer to the customer for a connection point and identifies the relevant infrastructure work needed to make the connection. Once this offer is signed the connection is recorded on the Transmission Entry Capacity (TEC) Register and forms a contractually binding connection location and timescale with which the transmission owner, such as National Grid, is required to connect the generation customer or undertake the works to facilitate their connection.

3.2.5 A connection offer will normally be given in respect of a particular geographical area. Sometimes this leads to a presumption as to the connection point located on the existing transmission network. In other circumstances where there is no or little existing transmission infrastructure, this will require the provision of new infrastructure. The post connection offer assessment process enables further evaluation of the preferred connection option and refinement of the preferred overall transmission solution. This process continues, informed by evolving circumstances and consultation, until an application is submitted for development consent in relation to a transmission project.

3.2.6 National Grid assesses the adequacy of its transmission system in accordance with the method defined in the NETS SQSS. We are required to assess power flows between regions of the transmission system (Planned Transfers). The Planned Transfer from the region is calculated by taking the Average Cold Spell (ACS) Peak Demand in the region and generation following the modelling set out in the NETS SQSS. The Planned Transfer is therefore the amount of power which will flow out of the region at ACS peak. Planned Transfer calculations will always consider the power flows for ACS peak demand conditions, as less generation will be entering the market when demand is lower.

3.2.7 Any transmission system is susceptible to faults that interfere with the ability of transmission circuits to carry power. Most faults are temporary, many are related to weather conditions such as lightning or severe weather, and many circuits can be restored to operation automatically in minutes after a fault. Other faults may be of longer duration and would require repair or replacement of failed electrical equipment.

3.2.8 Whilst some of these faults may be more likely than others, faults may occur at any time, and it would not be acceptable to have a significant interruption to supplies as a result of specified fault conditions, including combinations of faults. The principle underlying the NETS SQSS is that the NETS should have sufficient spare capability or "redundancy" such that fault conditions do not result in widespread supply interruptions. The level of security of supply has been determined to ensure that the risk of supply interruptions is managed to a level that maintains a minimum standard of transmission system performance. The faults we need to design the system to be compliant with are called "Secured Events".

3.2.9 The NETS SQSS defines the performance required of the NETS in terms of Quality and Security of Supply for secured events that at all times:

- Electricity system frequency should be maintained within statutory limits;
- No part of the NETS should be overloaded beyond its capability;
- Voltage performance should be within acceptable statutory limits; and
- The system should remain electrically stable.

3.3 Existing transmission network

3.3.1 The transmission system in the South East and East Anglia was primarily constructed in the 1960s, at the same time as much of the rest of the transmission system and has remained largely unaltered since.

3.3.2 The transmission system in East Anglia consists of a 212 km loop of circuits connecting Walpole, Necton, Norwich Main, Bramford, Pelham and Burwell Main substations. This loop connects to the rest of the transmission system to the north at Walpole; south at the Twinstead Tee; and south and west at Pelham. The loop connects substations to the transmission system by more than one route, thereby improving security of supply for local demand and the reliability of connection for generation in the region.

3.3.3 The transmission system in East Anglia was built primarily to serve consumer demand from homes and businesses in the region. Peak demand by 2029/30 is anticipated to be approximately 1,767 MW (total for demand substations of Walpole, Norwich Main and Bramford and with only minor demand being consumed at Sizewell).

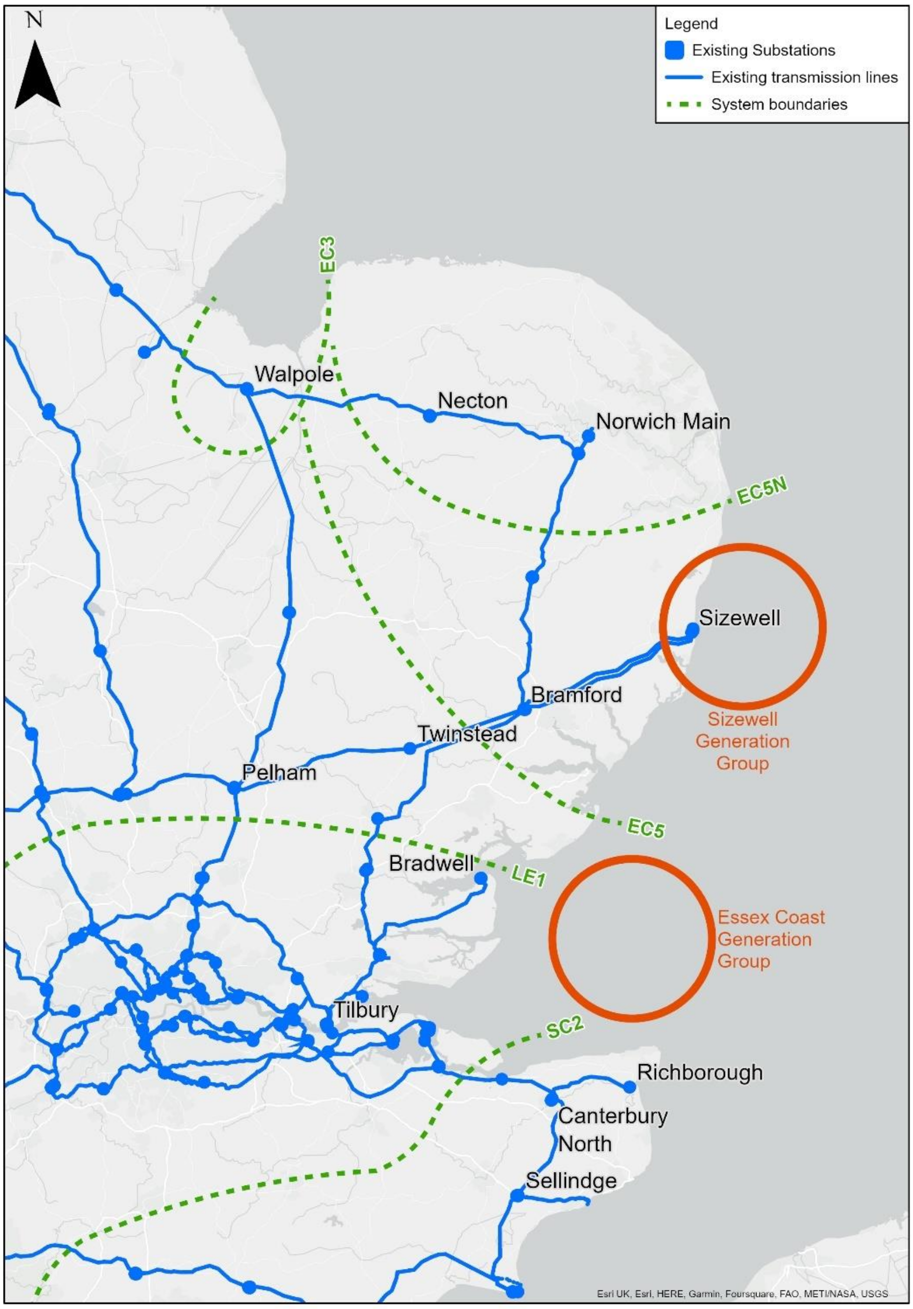
3.3.4 For many years the only significant power stations generating in the East Anglia region were the Sizewell A and the Sizewell B nuclear power stations, Spalding North and Sutton Bridge gas fired power stations, and some further smaller 132 kV connected gas fired power stations.

3.3.5 This generation capacity has recently been added to by several offshore windfarms with the existing generation totalling 7,687.4 MW of installed capacity. This is expected to grow substantially in coming years, as discussed further below.

3.3.6 The wider South East area, is made up of the 400 kV and 275 kV network which connects generation and demand in the major towns and cities of the wider South East and Midlands regions.

3.3.7 The existing transmission system in East Anglia and South East is shown in Figure 3.1 below, with the inclusion of the Bramford to Twinstead connection for which development consent is being sought from the Secretary of State following submission of our Development Consent Order in April 2023.

Figure 3.1 – East Anglia and South-East region transmission system and system boundaries



3.4 Need for future reinforcement of the East Anglia and South East transmission system

3.4.1 As discussed in the previous section, UK Government policy requires significant reinforcement of the transmission system to facilitate the connection of renewable energy sources and to transport electricity to where it is used. In particular, the British Energy Security Strategy sets targets for the connection of up to 50 GW of offshore wind by 2030 as a key part of a strategy for secure, clean and affordable British energy for the long term.

3.4.2 National Grid is responsible for ensuring compliance with the National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS), which sets out the criteria and methodology for planning and operating the system. In summary the reinforcement of East Anglia and South East is required for the following reason.

3.4.3 Without reinforcement the capacity of the East Anglia and South East existing network is insufficient to accommodate the connection of the proposed new power sources. The 'Thermal Boundary Export Limit' – the physical maximum energy capacity the system can accommodate during planned system faults – would be exceeded, preventing export of power to demand centres beyond East Anglia.

3.4.4 To address these SQSS compliance issues reinforcement of the network is required. Without reinforcement, in some conditions generators connecting in the area would be required to reduce their output. Generators would then have to be compensated via a 'constraint' payment, and additional payments made to non-constrained generators outside of the area to ensure that supply matches demand. These costs would be passed on to end consumers. ESO analysis shows that, in this case, predicted constraint costs are likely to significantly exceed those of reinforcement, providing a further driver to reinforce the system in addition to meeting the criteria of the SQSS.

3.4.5 The concept of 'boundary capacity and capability' plays an important role. A boundary notionally splits the system into two parts, crossing critical circuit paths that carry power between the areas where power flow limitations may be encountered. Where 'boundary capacity' – the capacity of the circuit(s) across the boundary – is exceeded against the standards, we must resolve the capacity shortfall. The standards against which National Grid assesses these shortfalls are set out in the SQSS. This is described in more detail later in this section.

3.5 Demand and new generation connecting in East Anglia

3.5.1 Demand in East Anglia (demand taken at Walpole, Norwich and Bramford substations) is expected to increase from 1,411 MW in 2022/23 to 1,767 MW in 2029/30.

3.5.2 The demand in the North of East Anglia (Walpole and Norwich) is expected to increase from 1,062 MW in 2022/23 to 1,320 MW in 2029/30.

Table 3.1 – 2022 WK24 Forecast Demand for the East Anglia Region

	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
East Anglia Demand (MW)	1,411	1,416	1,431	1,463	1,519	1,598	1,690	1,767
North East Anglia Demand (MW)	1,062	1,066	1,078	1,102	1,142	1,199	1,260	1,320

3.5.3 The increases in local demand are relatively modest while significant expansion of generation is expected in the region. In the East Anglia region, connection agreements have been signed in respect of 17,310.1 MW of new generation (total generation of 24,997.5 MW minus Existing Generation of 7,687.4 MW). These future connection agreements comprise a large volume of offshore wind generation (including East Anglia Offshore Wind), gas-fired generation, energy storage projects, and a nuclear power station (at Sizewell C). Table 3.2 below gives details.

Table 3.2 – Planned Generation for East Anglia

Table 3.2 - Planned Generation for East Anglia
Generation Data from the ESO TEC registers as of 01/08/23
(#Generation in Sizewell genration group *Generation Impacting EC5N, $Generation using Fossil Fuels)

Completion Year	Generation Name	Substation	Plant Type	Total Installed Capacity (MW)	Availability Factor	Scaled Generation Capacity (MW)			
Existing	Sizewell B	Sizewell 400kV	Nuclear	1,230.0 MW	0.85	1,045.5 MW			#
Existing	Greater Gabbard Offshore Wind	Lieston 400kV	Wind	500.0 MW	0.7	350.0 MW			#
Existing	Great Yarmouth	Norwich 400kV	CCGT	420.0 MW	0.83	348.6 MW	*	$	
Existing	Sherringham Schoal Offshore Wind	Necton 400kV	Wind	315.0 MW	0.7	220.5 MW	*		
Existing	Gunfleet Sands II	Gunfleet	Wind	64.0 MW	0.7	44.8 MW			
Existing	Gunfleet Sands I	Gunfleet	Wind	99.9 MW	0.7	69.9 MW			
Existing	Kings Lynn A	Walpole 132kV	CCGT	395.0 MW	0.83	327.9 MW	*	$	
Existing	Sutton Bridge A	Sutton Bridge 400kV	CCGT	850.0 MW	0.83	705.5 MW	*	$	
Existing	Peterborough	Walpole 132kV	CCGT	245.0 MW	0.83	203.4 MW	*	$	
Existing	Spalding North Power Station	Spalding North 400kV	CCGT	950.0 MW	0.83	788.5 MW	*	$	
Existing	Spalding Energy Extension	Spalding North 400kV	CCGT	299.0 MW	0.83	248.2 MW	*	$	
Existing	Dudgeon Wind Farm	Necton 400kV	Wind	400.0 MW	0.7	280.0 MW	*		
Existing	Peak Gen	Walpole 132kV	AGT	20.5 MW	0.83	17.0 MW	*	$	
Existing	Race Bank Windfarm	Walpole 400kV	Wind	565.0 MW	0.7	395.5 MW	*		
Existing	Lincs Wind Farm	Walpole 400kV	Wind	265.0 MW	0.7	185.5 MW	*		
Existing	Galloper Windfarm	Sizewell 132kV	Wind	348.0 MW	0.7	243.6 MW			#
Existing	EPR Thetford	Bramford 400kV	Biomass	41.0 MW	0.83	34.0 MW			
Existing	East Anglia One	Bramford 400kV	Wind	680.0 MW	0.7	476.0 MW			
2022	Pivoted Power (Walpole)	Walpole 400kV	Energy Storage	49.9 MW	0.83	41.4 MW	*		
2022	Brook Farm BESS	Bramford 400kV	Energy Storage	49.9 MW	0.83	41.4 MW			
2023	Walpole Green Ltd	Walpole 400kV	Energy Storage	49.9 MW	0.83	41.4 MW	*		
2023	Pivoted Power (Bramford)	Bramford 400kV	Energy Storage	49.9 MW	0.83	41.4 MW			
2023	Bramford Green Stg 1	Bramford 400kV	Energy Storage	49.9 MW	0.83	41.4 MW			
2023	Yare Power	Norwich 400kV	CCGT	49.5 MW	0.83	41.1 MW	*	$	
2024	ENSO Green Holdings	Walpole 400kV	Energy Storage	100.0 MW	0.83	83.0 MW	*		
2024	Bramford Green stg 2	Bramford 400kV	Energy Storage	7.1 MW	0.83	5.9 MW			
2024	Eurolink	Lieston/Sizewell	Interconnector	1,600.0 MW	1	1,600.0 MW			#
2025	East Anglia Two	Lieston 400kV	Wind	860.0 MW	0.7	602.0 MW			#
2025	Kings Lynn B	Kings Lynn 400kV	CCGT	1,700.0 MW	0.83	1,411.0 MW	*	$	
2025	Vanguard	Necton 400kV	Wind	1,320.0 MW	0.7	924.0 MW	*		
2026	Hornsea Power Station 3 - Stg 1	Norwich 400kV	WInd	2,250.0 MW	0.7	1,575.0 MW	*		
2026	East Anglia One North	Lieston 400kV	Wind	860.0 MW	0.7	602.0 MW			#
2026	East Anglia Three	Bramford 400kV	Wind	1,200.0 MW	0.7	840.0 MW			
2026	Norfolk Boreas	Necton 400kV	Wind	1,320.0 MW	0.7	924.0 MW	*		
2027	Vanguard East 1	Necton 400kV	Wind	960.0 MW	0.7	672.0 MW	*		
2027	Equinor	Norwich 400kV	Wind	719.0 MW	0.7	503.3 MW	*		
2027	Nautilus	Lieston/Sizewell	Interconnector	1,500.0 MW	1	1,500.0 MW			#
2028	Hornsea Power Station 3 - Stg 2	Norwich 400kV	Wind	750.0 MW	0.7	525.0 MW	*		
2028	Vanguard East 2	Necton 400kV	Wind	360.0 MW	0.7	252.0 MW	*		
2029	Sizewell C Stage 1	Sizewell 400kV	Nuclear	1,670.0 MW	0.85	1,419.5 MW			#
2030	Race Bank Extension	Walpole	Wind	565.0 MW	0.7	395.5 MW	*		
2030	Sizewell C Stage 2	Sizewell 400kV	Nuclear	1,670.0 MW	0.85	1,419.5 MW			#
2030	Alcemi Bramford Battery	Bramford 400kV	Energy Storage	500.0 MW	0.83	415.0 MW			
2031	Norwich 100MW BESS	Norwich 400kV	Energy Storage	100.0 MW	0.83	83.0 MW	*		
Total EC5 Existing Generation (MW)				**7,687.4 MW**		**5,984.3 MW**			
Total Generation Sizewell gneration group # (MW)				**10,238.0 MW**		**8,782.1 MW**			
Total Generation Impacting EC5N* (MW)				**15,017.8 MW**		**11,192.2 MW**			
Total EC5 Genration Existing and Contracted with No Fossil Fuel Contribution $ (MW)				**23,068.5 MW**		**17,893.1 MW**			
Total EC5 Generation Existing and Contracted				**27,997.5 MW**		**21,984.2 MW**			
Forecast ACS Peak Demand 2029/30						**1,767.0 MW**			
Forecast ACS Peak Demand 2029/30 Impacting EC5N*						**1,320.0 MW**			
Existing Planned Transfer at ACS Peak with All Generation (Existing Generation - Existing Demand)						**4,573.3 MW**			
Transfer at ACS Peak with All Generation Sizewll Group (Total Generation# - No Demand in the group)						**8,782.1 MW**			
Transfer at ACS Peak with All Generation Impacting EC5N (Total Generation* - Peak Demand*)						**9,872.2 MW**			
Minimum EC5 Planned Transfer at ACS Peak with All Generation (Total Generation ($ excl fossil fuel) - Peak Demand)						**16,126.1 MW**			
Maximum EC5 Planned Transfer at ACS Peak with All Generation (Total Generation - Peak Demand)						**20,664.2 MW**			

3.6 Planned transfers

3.6.1 To assess SQSS compliance, National Grid is first required to assess power flows between areas of the Transmission System. From a security of supply perspective (‘Economy Planned Transfer’), we seek to ensure that transmission system infrastructure is adequate to meet national demand and customer generation requirements during operating conditions that could reasonably occur. It is generally the case that if the capacity of the transmission system is sufficient to meet Average Cold Spell (ACS) Peak demand it will have sufficient capacity to meet lower levels of demand.

3.6.2 The total generation capacity typically connected to the NETS exceeds maximum demand. This is known as ‘Plant Margin’. Historically, Plant Margin has been a minimum 120% of peak demand (i.e. there is 20% more generation installed than required to meet demand). This allows the operation of generation below its maximum output to cover for breakdowns of generators, intermittency of energy source (wind) and to cover faults of generation while in service. Current generation market arrangements mean that simultaneous generation at maximum output is unlikely and National Grid is, therefore, not required by SQSS to provide transmission system infrastructure capable of accommodating the total output from all connected generators.

3.6.3 The amount of power expected to be transferred between two areas of the transmission system during normal operation is referred to as the ‘Economy Planned Transfer’. The Economy Planned Transfer is derived by applying an Availability Scaling Factor (or ‘scaling factor’) to the installed capacity of each power station according to the type of generation.

3.6.4 The SQSS defines the technique that should be used to scale generation outputs for certain types of generators. Generators with fixed scaling factors (DT) are:

- Nuclear and fossil fuel power with carbon capture and storage DT = 0.85.
- Wind, Wave and Tidal DT = 0.7.
- Pumped Storage DT = 0.5.
- Interconnectors Considered importing at Peak DT = 1.0.

3.6.5 Other plant types (such as gas turbines, biomass and energy storage) are not subject to fixed scaling factors in the SQSS. It is therefore necessary to make assumptions about the extent to which this generation would be available. As shown in Table 3.2 above, in the East Anglia Region, the Transmission Entry Capacity Register (’TEC') includes approximately 5 GW of gas turbine (CCGT and AGT) plant, 1 GW of energy storage and a small amount of biomass (41 MW).

3.6.6 Typically, these sources of energy have been scaled in SQSS planning using a straight scaling factor of 0.83 (based on assumed plant margin at 120% - i.e. 1/120%). However, given the planned transition towards low-carbon sources of energy and the 2050 net zero target, this is likely to represent an overestimate as fossil fuel-based generators will gradually reduce their contribution and generation such as offshore wind will be more prevalent.

3.6.7 The assessment presented here therefore applies a range to the scaling factor for gas turbine generation. 0.83 is assumed as the top of the range (i.e. the maximum availability possible), and consideration that fossil fuel contribution will ultimately be phased out over the coming 25 years. Therefore, the bottom of the range assumes no contribution from fossil fuelled stations such as gas fired stations). Such a low availability factor will likely represent a significant underestimate of the availability of gas plant given that significant amounts of current and contracted future generation will be connected to the system in the short to medium term. However, this is considered an appropriate approach to demonstrate the robustness of need for reinforcement.

3.6.8 The Planned Transfer from the region is calculated by taking the ACS peak demand in the region from the total scaled generation. The Planned Transfer is therefore the amount of power which will flow out of the region at ACS peak. Planned Transfer calculations will always consider the power flows for ACS peak demand conditions, as less generation will be entering the market when demand is lower.

3.6.9 The results of the analysis of the Economy Planned Transfer for the East Anglia region are shown in Table 3.2 above, which captures the latest forecast demand data for 2029/30 generation connection dates recorded on the TEC and Interconnector Register publicly available on the ESO website at the time of publication of this document. These show connections of generators and interconnectors up to 2031. Gas turbine generators are included with a scaling factor of 0.83 but as discussed above a minimum planned transfer figure has also been provided assuming contribution for gas fired station is zero.

3.6.10 The total maximum contracted scaled generation in East Anglia (i.e. including gas plant) at the time of maximum demand is forecast to be 21,984.2 MW as compared to 27,997.5 MW of installed generation capacity. The demand in the region at the time of system peak will be 1,767 MW.

3.6.11 This results in a forecast maximum Planned Transfer in 2031 of 20,664.2.2 MW export (21,984.2 MW minus 1,767 MW).

3.6.12 The minimum forecast planned transfer with no contribution from fossil fuels in 2031 would be 16,126.1 MW export (17,893.1 MW minus 1,767 MW).

3.6.13 Both the maximum and minimum forecast planned transfers are significant increases on the existing Planned Transfer export condition of 4,573.3 MW.

3.7 Boundary capacity and capability

3.7.1 The capacity of the transmission system is based on the physical ability of electrical circuits to carry power. Each circuit has a defined capacity and the total capacity of the circuits in a region or across a boundary is the sum of all of the capacity of all the circuits.

3.7.2 The capability of the transmission system is the natural flow of energy that can occur in the infrastructure comprising the network. Due to the physical properties of the transmission system, this is often not as great as the theoretical capacity of the infrastructure in question.

3.7.3 Where power flows are constrained by the transmission system across a specific number of circuits, this is termed a “boundary” by the ESO. Such boundaries are used in the ETYS to identify constraints which may require changes to the transmission system in the next 10 years.

3.7.4 Groups of existing generating stations and/or proposed generating stations connecting in a particular geographical area of the transmission system are known as ‘generation groups’. These are considered when assessing the network for compliance with the generation connection criteria of the NETS SQSS.

3.7.5 Where capacity and capability of the transmission system are not sufficient, either from a generation group or across a boundary, we will be required to reinforce the network. It does this by either modifying the existing network (if possible) and/or constructing additional transmission infrastructure to resolve the shortfall.

3.7.6 The East Anglia and South East regions have a number of system boundaries which determine the capability of the network to accommodate demand and generation.

3.7.7 The boundaries impacted as part of the need case shown in figure 3.1 for this document are as follows:

- EC3 – Walpole Area (generation group).
- EC5N North – North of East Anglia (generation group).
- EC5 – East Anglia Boundary.
- Sizewell (generation group) – also sometimes referred to by the ESO as ‘EC6’.
- Essex Coast (generation group).
- LE1 – North London Boundary.
- SC2 – South Coast Connection boundaries.

East Anglia fault and impact on Boundaries EC5N and EC5

3.7.8 For the East Anglia region, the worst-case fault is the loss of the Walpole – Burwell – Pelham double circuits as shown in Figure 3.2. The SQSS requires the transmission system to manage the planned transfers in Table 3.3. Under this fault condition network flow remains in a southerly direction with generation from Spalding North to the south flowing in the direction of Bramford substation.

3.7.9 In this situation the circuits across EC5N and EC5 must be capable of exporting the power generated in each of those areas along with the energy entering from Spalding North. Table 3.3 below shows the planned transfer required with the capability of the boundary based upon the capacity of the export circuits from EC5N and EC5.

Figure 3.2 – East Anglia fault and impact on Boundaries EC5N and EC5

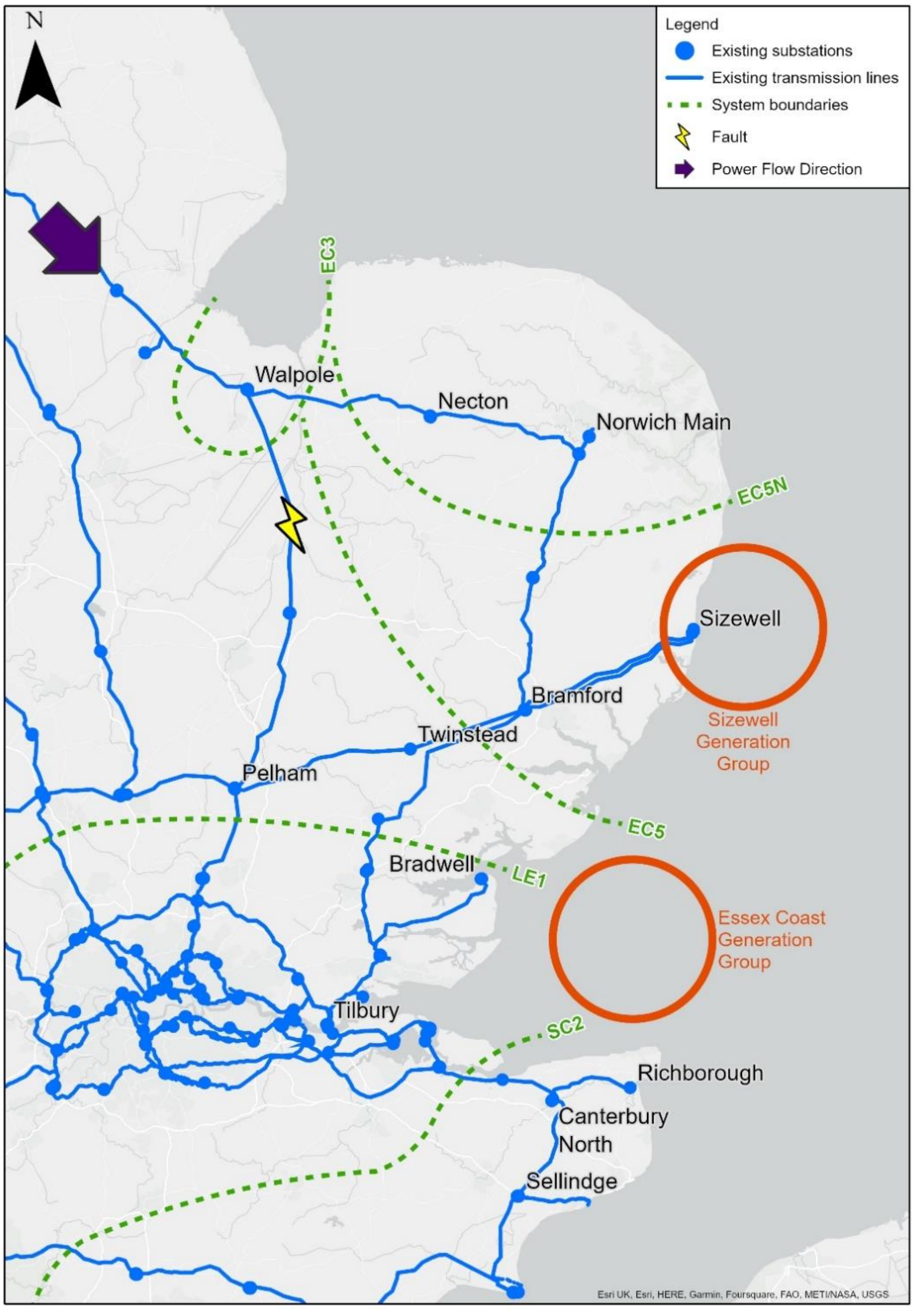


Table 3.3 – Planned Transfer requirements

Planned Transfer		Post Fault Capability by 2031	Planned Transfer Boundary Deficit
EC5N (Maximum)	9,872 MW	6,380 MW	-3,492 MW
EC5 (Maximum)	20,664 MW	12,580 MW	-8,084 MW
EC5N (Minimum*)	9,188 MW	6,380 MW	-2,808 MW
EC5 (Minimum)	16,126 MW	12,580 MW	-3,546 MW

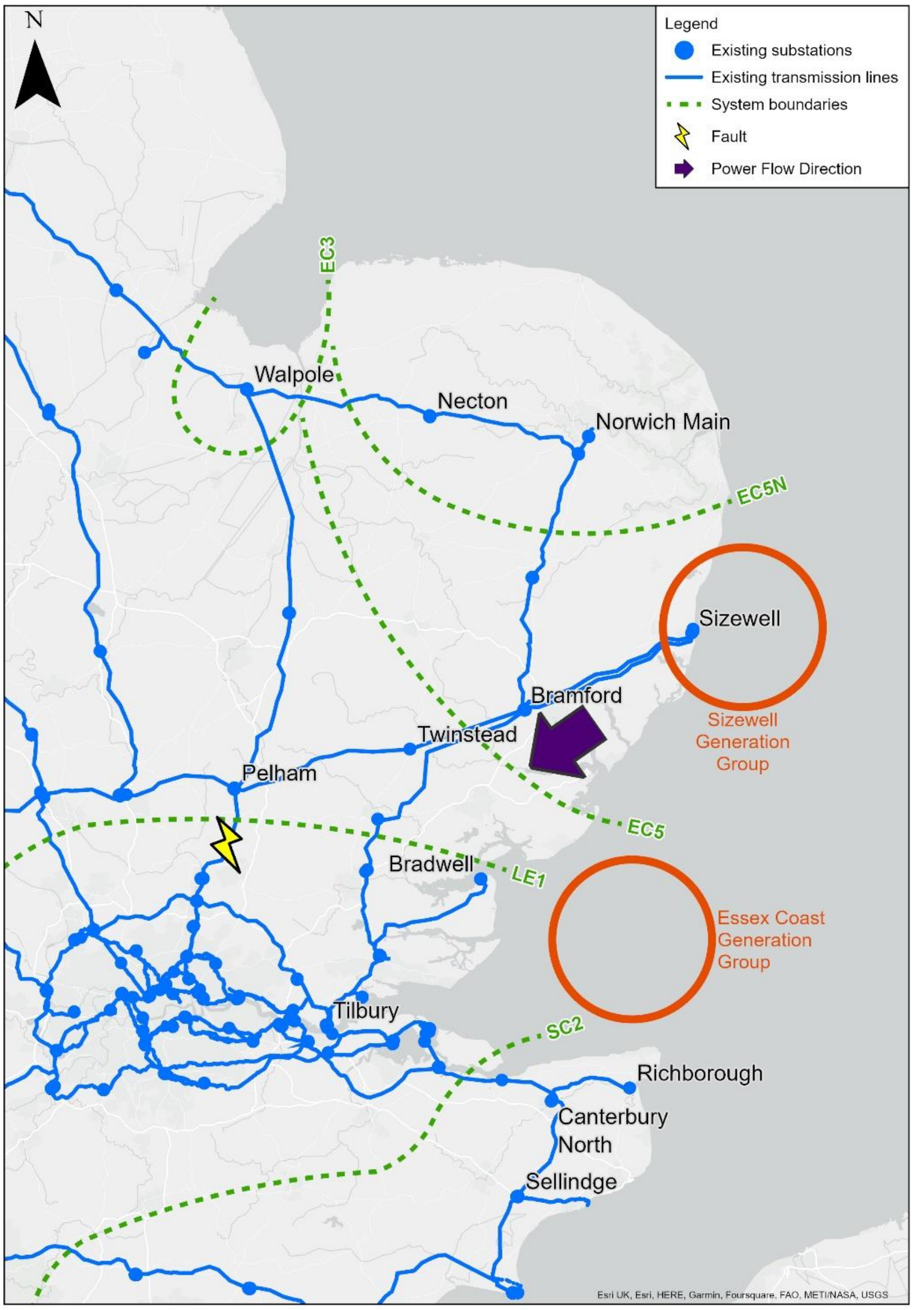
3.7.10 Table 3.3 above shows the maximum transfer required while fossil fuel gas fired power stations contribute to the system. The minimum levels assume gas fired power stations are not contributing.

3.7.11 EC5N minimum level is set to all remaining low carbon generation at full output as the generation criteria requires the generator being considered at full output, and all others in the group set to a level which ought reasonably to be expected. As these generators are all wind, if conditions are perfect for full output in the region, they all would be maximising output. However even at this level the reinforcement is required.

3.7.12 As described earlier the minimum levels are unlikely to occur as the Gas plant will continue to contribute to the energy system for the next 25 years and when this generation does close it will be replaced by further new generation connecting to the grid. However, it is a good test to show that under all circumstances system reinforcement is required in the range of 3,500 MW to 8,000 MW across and out of the East Anglia region. With the SQSS requiring us to design the network to accommodate the 8,000 MW upper range.

LE1 Boundary Fault and Impact

Figure 3.3 – LE1 Boundary Fault and Impact



3.7.13 The region south of the EC5 boundary is the proposed connection location of the North Falls 1000 MW and Five Estuaries 1080 MW wind farms.

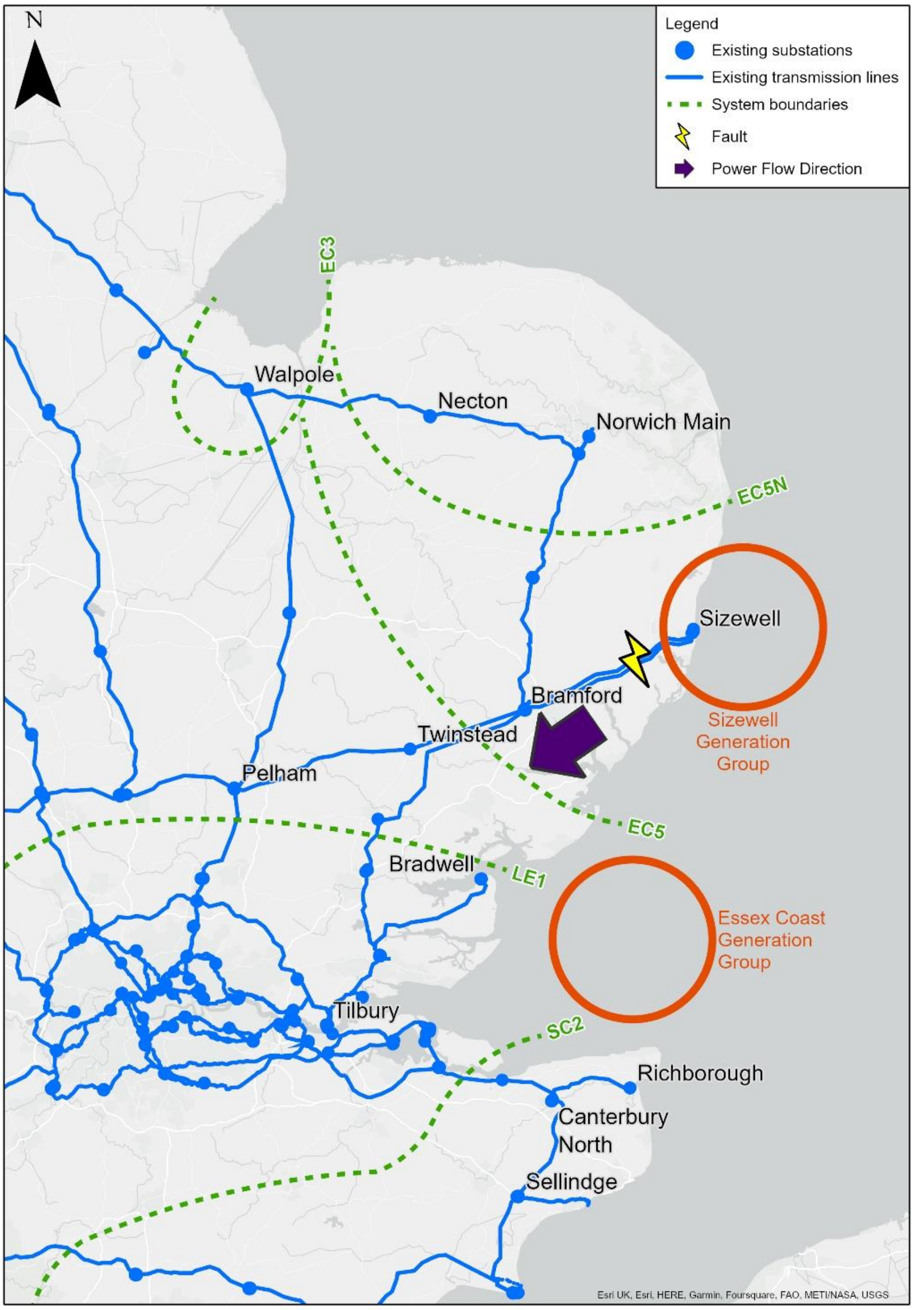
3.7.14 For the LE1 boundary the worst case fault is for the Pelham – Rye House double circuit as shown in Figure 3.3. During this fault the East Anglia generation will naturally seek to flow down the Bramford – Braintree – Rayleigh circuits causing them to overload above their maximum potential capability of 6380 MW. These circuits experience loadings in the order of 11,000 MW with a deficit of -4,620 MW of capability.

3.7.15 With a requirement to provide additional 2,956 MW [(1000 MW + 1080 MW) x 0.7 + 1500 MW] for the connection of North Falls, Five Estuaries and Tarchon as described as the Essex Coast Generation Group below increasing the deficit to -7576 MW.

3.7.16 This deficit along with two generators seeking connection in the area shows there is insufficient capacity across this part of the LE1 boundary and requires reinforcement.

Sizewell Generation Group

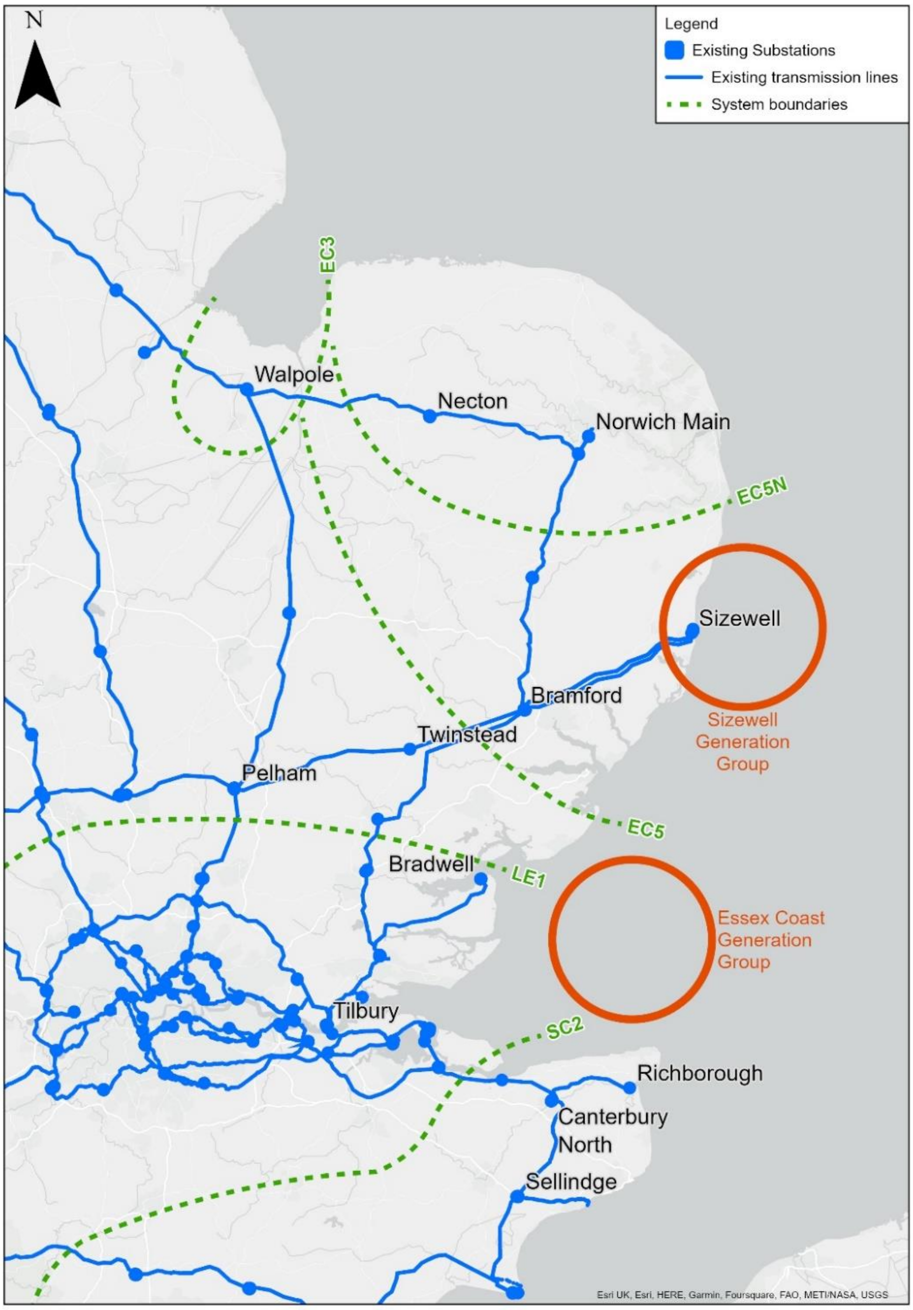
Figure 3.4 – Sizewell Generation Groups fault and impact



3.7.17 For the Sizewell Generation Group the worst-case fault is for one of the two double circuits connecting Bramford to Sizewell as shown in Figure 3.4 to be lost whilst the second double circuit remains in operation. This leaves the remaining double circuit with a maximum potential capability of 6,930 MW and generation transfer of 8782.1 MW leaving a deficit of more than -1852.1 MW. This requires the Sizewell Generation Group to be reinforced for this condition.

Essex Coast Generation Group

Figure 3.5 – Essex Coast Generation Need



3.7.18 National Grid also has contracted connections for new generation and interconnectors located off the Essex Coast with proposed connections between the EC5 boundary and the LE1 boundary. The 3 proposed connections are as follows: -

- Tarchon Energy Limited Interconnector (1,500 MW By 2030)
- North Falls offshore Windfarm (1,000 MW by 2030)
- Five Estuaries Offshore Windfarm (1,080 MW by 2030)

3.7.19 These connections are proposed to be made to the network at a location which can accommodate the combined 3580 MW of generation. This requires a minimum of 3 transmission circuits to connect the generation to meet the minimum loss of infeed requirements of the NETS SQSS.

SC2 Boundary

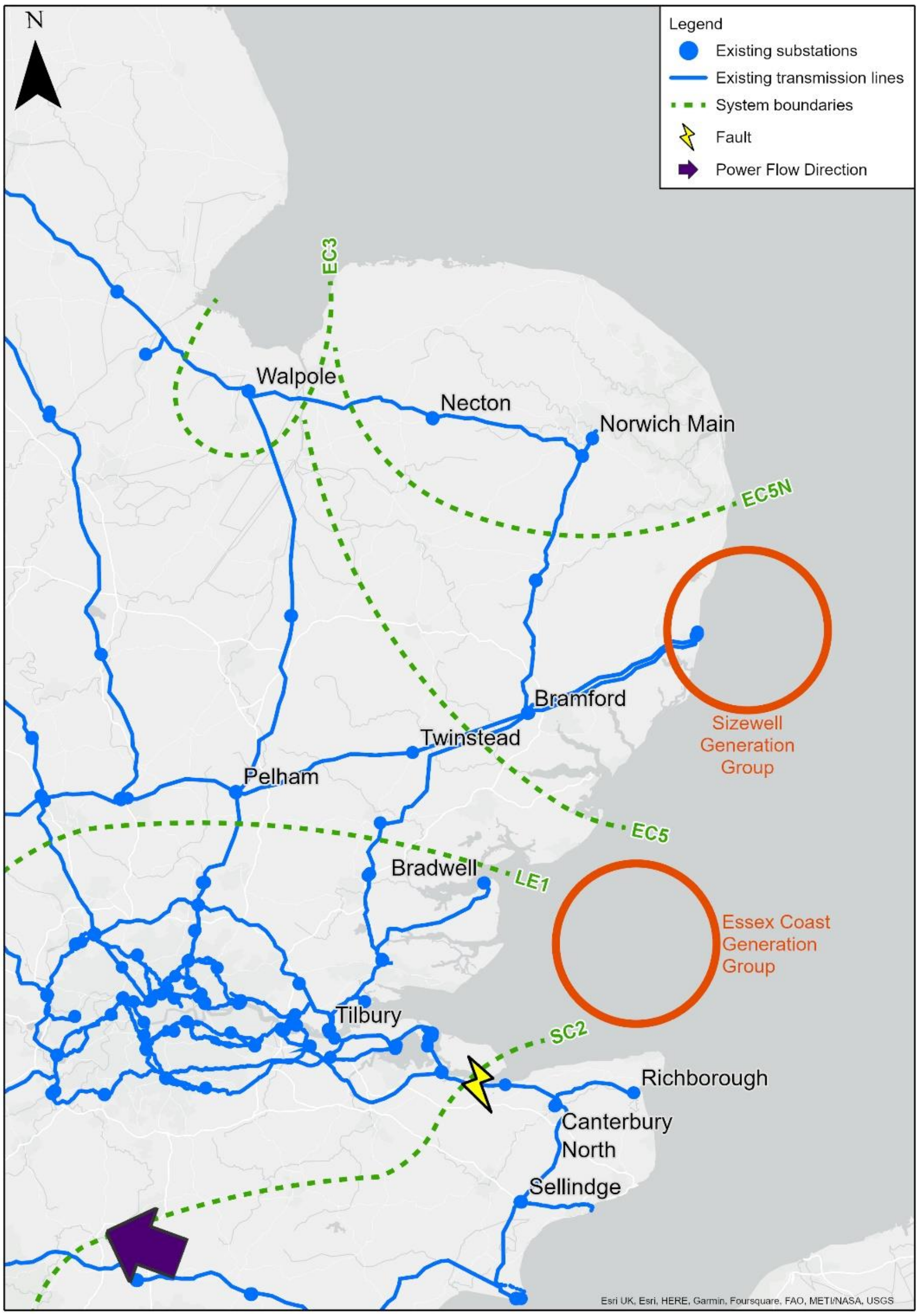
3.7.20 Table 3.4 shows the existing and contracted generation expected to connect in within the SC2 boundary of Kent by 2031. The existing SC2 boundary capability is 4500MW with the capability limited by thermal and voltage stability issues. The existing planned transfer from the SC2 boundary is 4,313MW, with +200MW of capacity available.

Table 3.4 – Planned Generation and Planned Transfer for Boundary SC2

Table 3.4 - Planned Generation and Planned Transfer for Boundary SC2 (Kent Area)
Generation Data from the ESO TEC registers as of 03/10/23
(#Nuclear and CCGT gneration)

Completion Year	Generation Name	Substation	Plant Type	Total Installed Capacity (MW)	Availability Factor	Scaled Generation Capacity (MW)
Existing	Eleclink	Sellindge	Interconnector	1,000.0 MW	1	1,000.0 MW
Existing	IFA Interconnector	Sellindge	Interconnector	2,000.0 MW	1	2,000.0 MW
Existing	Nemo Link	Richborough	Interconnector	1,020.0 MW	1	1,020.0 MW
Existing	London Array	Cleve Hill	Wind	630.0 MW	0.7	441.0 MW
Existing	UK power reserve ltd	Sellindge	CCGT	10.0 MW	0.83	8.3 MW
Existing	Dungeness B	Dungeness	Nuclear	1,120.0 MW	0.85	952.0 MW
Existing	Shoreham VPI Power	Bolney	CCGT	420.0 MW	0.83	348.6 MW
2024	Cleve Hill Solar Park	Cleve Hill	PV Solar	350.0 MW	0.7	245.0 MW
2024	Pivoted Power Sellindge	Sellindge	Energy Storage	49.9 MW	0.7	34.9 MW
2024	Bolnley Green	Bolney	Energy Storage	49.9 MW	0.7	34.9 MW
2025	ENSO Green Holdings ltd	Canterbury North	Energy Storage	49.9 MW	0.7	34.9 MW
2025	Sheaf Energy Ltd	Richborough	Energy Storage	249.0 MW	0.7	174.3 MW
2027	Pivoted Power Bolney	Bolney	Energy Storage	49.9 MW	0.7	34.9 MW
2027	Kulizumboo Interconnector	Canterbury North	Interconnector	700.0 MW	1	700.0 MW
2029	Blue Plannet Solar	Dungeness	PV Solar	500.0 MW	0.7	350.0 MW
2029	Low Carbon Solar Park 14 ltd	Dungeness	PV Solar	500.0 MW	0.7	350.0 MW
2029	Ninfield Greener Grid Park	Ninfield	Energy Storage	49.9 MW	0.7	34.9 MW
2030	Orron Energy Development	Sellindge	PV Solar	1,000.0 MW	0.7	700.0 MW
2031	Newchurch SSE Utility Solutions ltd	Dungeness	PV Solar	400.0 MW	0.7	280.0 MW
2031	Ninfeild Green Energy Centre ltd	Ninfield	PV Solar	600.0 MW	0.7	420.0 MW
2031	Hookers Farm BESS	Bolney	Energy Storage	250.0 MW	0.7	175.0 MW
Total Existing Generation (MW)				6,200.0 MW		5,769.9 MW
Total Generation Impacting SC2 (MW)				10,998.5 MW		9,338.9 MW
Total Generation Impacting SC2 (MW) (Minus Life Limited Dungeness B & CCGT)				9,448.5 MW		8,030.0 MW
Forecast SC2 ACS Peak Demand 2029/30						1,456.0 MW
Existing Planned Transfer at ACS Peak with All Generation (Existing Generation - Existing Demand)						4,313.9 MW
SC2 Transfer at ACS Peak 2031 all generation						7,882.9 MW
SC2 Transfer at ACS Peak 2031 all generation (Minus Life Limited Dungeness B & CCGT)						6,574.0 MW

Figure 3.6 – SC2 boundary fault and impact



3.7.21 Figure 3.6 For the SC2 Boundary group the worst-case fault is for the double circuits connecting Canterbury North to Kemsley as shown in Figure 3.6, with the remaining circuit capability being 4,500 MW and maximum capacity the two circuits between Bolney to Lovedean being 5,873 MW. The transfer required by 2031 excluding existing nuclear and CCGT is 6,574 MW. This is in excess of both the capability and capacity of SC2 causing both overloads and voltage stability issues on the south coast.

3.7.22 There will be 4,720 MW of interconnectors in this region along with 4,728 MW of renewable generation and storage. This leaves the remaining double circuit with 4,500 MW capability and 5,873 MW of capacity and planned transfer of 6,574 MW leaving a deficit of between 701 – 2,074 MW.

3.7.23 This requires the SC2 boundary to be reinforced for this condition. Whilst provision of additional voltage support can increase circuit capability by circa 300 MW, this would require 1,800MW of capacity from the SC2 area.

3.8 Need case conclusion

3.8.1 As described above there are five distinct issues that need to be resolved by system reinforcement:

- Provision of 8,084 MW of capacity across East Anglia EC5 Boundary and 3,492 MW of capacity across EC5N Boundary.
- Provision of 7,576 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,580 MW of connection capacity for the Essex Coast Generation Group
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

3.8.2 The remainder of this report considers the options required to resolve the provision of circa 2000 MW (i.e greater than 1,800 MW) between Sizewell and the SC2 Boundary.

4. Identification of strategic options

4.1 Introduction

4.1.1 When a need to reinforce the transmission system is established, we bring together a multi-disciplinary scheme team to evaluate a wide range of options. This team produces a list of strategic options which can be further refined through evaluation processes and which are described within this report. The scheme team keeps the options under review as changes to the drivers emerge. Through this review, options can be modified, or deselected and new options can be added. This section provides the chronological history of the options that are evaluated in this Strategic Options Report and how the process was used to arrive at this list.

4.2 Initial Electricity System Operator analysis

4.2.1 A new offshore High Voltage Direct Current (HVDC) link between South East of England and East Anglia was first assessed in the 2018/2019 NOA. This option crossed multiple system boundaries, and was included for comparison with other options that only addressed the need in the South East of England. The 2018/2019 NOA recommended a ‘proceed’ signal for this option. Strategic options were then developed that explored alternative HVDC links that could provide the reinforcement required. This work identified that a connection between East Anglia and Richborough in Kent provided this reinforcement, this was then reflected in the subsequent 2019/2020 NOA.

4.2.2 Additional network studies in East Anglia were undertaken to confirm which connection point provided the best value to customers whilst minimising potential environmental and socio-economic impacts. These studies identified that the HVDC Link needed to connect into the Sizewell area in order to maximise the system benefit.

4.3 Corridor and Preliminary Routeing and Siting Study

4.3.1 The analysis was published in October 2022 in the Corridor and Preliminary Routeing and Siting Study (CPRSS). This identified four strategic options to address the need:

- SL1 – Sizewell Area to Sellindge subsea – approx. 180 km;
- SL2 – Sizewell Area to Richborough subsea approx. 120 km;
- SL3 – Sizewell Area to Canterbury subsea approx. 120 km;
- LL 1 – Sizewell Area to Canterbury onshore approx. 220 km.

4.3.2 Part of the needs case was, and remains, to manage requirements under the NETS SQSS and economic criteria from the Sizewell area. Therefore, all options to satisfy the need, were required to start from the Sizewell area in this case.

4.3.3 For each of the strategic options, we considered the technology options available for transmission system reinforcement, environmental and socio-economic constraints, lifetime costs of each technology option, as well as initial capital cost. Two technology options were considered for the offshore options: AC Subsea cable and HVDC Subsea cable. Four technology options were considered for the onshore option: overhead line (OHL), underground cables, Gas Insulated Lines (GIL) and onshore HVDC

4.3.4 Onshore option LL1 (Sizewell to Canterbury), for a complete overhead line AC solution, would be likely to be the lowest capital cost connection, but taking account of the lifetime cost of this solution it would be comparable with the offshore 2GW HVDC solutions. Option LL1 would also be subject to increased costs for crossing of the River Thames (likely by tunnel) and for any underground cable sections. The CPRSS also concluded that this option did not pass the technical and benefits filters in our options appraisal methodology, and therefore LL1 was not carried forward for environmental and socio-economic evaluation at this time.

4.3.5 None of the environmental and socio-economic impacts of the remaining (offshore) options SL1, SL2 and SL3 were considered to present in-principle issues that could not be mitigated with careful consideration of routeing and use of appropriate technologies to specific constraints, as is consistent with the existing and emerging NPSs against which proposals for nationally significant infrastructure projects are assessed.

4.3.6 The lowest cost subsea option is equal between option SL2 and SL3, a connection from Sizewell Area to Richborough or Canterbury utilising a 2000 MW Voltage Source Converter (VSC) HVDC connection.

4.3.7 From an environmental and socio-economic perspective SL2 was preferred to SL3 due to the marine constraints off the north Kent coast and onshore siting opportunities close to Richborough substation. As such the CPRSS concluded that SL2 was the option that would best balance overall technical, cost, environmental and socio-economic considerations.

5. Options assessment process

5.1.1 National Grid has published "*Our Approach to Consenting*" which sets out how we develop our strategic proposal. We apply the following approach to evaluate options we take forward.

5.1.2 Firstly, we identify if our existing network could be modified or enhanced to deliver the required connection or increase in capacity.

5.1.3 If we identify there is a need that is beyond the capability of our existing network, as clearly set out in our project need case, we consider strategic options to provide the required increase in capacity.

5.1.4 We apply a technical filter as part of this assessment to ensure any solution meets the need, either individually or as part of a wider group of reinforcements. There are many ways to achieve increases to our network capability. To allow us to focus on those that best meet our obligations to the environment and consumers we apply a "benefits filter", which ensures any option we present has a comparable benefit over an alternative. The criteria for an option to be considered are any of the following:

- an environmental benefit;
- a technical system benefit; or
- a capital and lifetime cost benefit.
- Where the benefits of options are very similar to each other, options will be included for appraisal to ensure we capture possible solutions that are of very similar capability.

5.1.5 All options taken forward for appraisal are evaluated in respect of environmental constraints, socio-economic effects, technology alternatives, capital and lifetime costs. Undertaking this appraisal ensures stakeholders can see how we have made our judgments and balanced the relevant factors in accordance with our legal duties.

5.1.6 The assessment process considers the following areas:

- Environmental assessment topics which consider whether there are environmental constraints or issues of sufficient importance to influence decision making at a strategic level, having particular regard for internationally or nationally important receptors.
- Socio-economic topics which consider whether there are socio-economic constraints or issues of sufficient importance to influence decision making at a strategic level, having particular regard for internationally or nationally important receptors.
- Consideration of technical benefits includes, whether the option is providing the required capacity to meet the need case; whether the option has particular system benefits over alternatives; whether the option introduces any system complexity that would cause system operability issues.

5.1.7 Capital and lifetime costs consider a range of factors, which are listed below;

- Capital cost of the substation and wider works

- Capital cost of the circuit costs for each technology appraised.

5.1.8 Circuit lifetime costs, including circuit capital cost, cost of loses over 40 years and cost of operation over 40 years.

5.1.9 When considering each strategic option, we estimate circuit cost information for the following technology options for all land-based options:

- 400 kV alternating current (AC) overhead line
- 400 kV AC underground cable
- 400 kV AC gas insulated line (GIL)
- 525 kV high voltage direct current (HVDC) underground cable and converter stations

5.1.10 When considering each strategic option, we provide circuit cost information for the following technology options for all offshore based options:

- 400 kV AC Offshore cable
- 525 kV HVDC Offshore cable and converter stations

5.1.11 A full evaluation and costs used in our assessments can be found in the Appendices.

5.1.12 In this appraisal, all options are considered using information appropriate to this stage of their development on the assumption that they are deliverable in a reasonable timescale. Timescales and deliverability would only be considered further in the assessment process should they become differentiating factors in the selection of the option that best meets our environmental and legal obligations. If these issues of delivery timescales and risk do become differentiating factors in selection of an option, the issue would be set out clearly in the options conclusion. If it is not differentiating the factor will not be considered further for this assessment.

5.1.13 At the initial appraisal stage, we prepare indicative estimates of the capital costs. These indicative estimates are based on the high-level scope of works defined for each strategic option in respect of each technology option that is considered to be feasible. As these estimates are prepared before detailed design work has been carried out, we make equivalent assumptions for each option. Final project costs for any solution taken forward following detailed design, consenting and mitigation will be in excess of any high-level appraisal cost. However, all options would incur these increases proportional to initial estimate in the development of a detailed solution. This methodology ensures that all options for appraisal proposes are compared on a like for like basis.

5.1.14 Strategic options are identified at a very high level as being electrical solutions between geographic points. Therefore, the potential circuit lengths are derived by taking a straight-line distance between the points and adding 20% to accommodate potential route deviations that might be required if the route proceeds forward to more detailed routeing and siting. Where a clear obstacle exists such as an estuary, water course or geographical feature an alternative route length will be derived and explained in the option. Where an offshore alternative is presented, straight lines will be used to a mid-point offshore and 20% added to provide variation in route length.

5.1.15 These initial option lengths do not define route corridors, and environmental appraisal is provided over a wide study area between points of connection. Any routes for circuit technologies to take would be subject to detailed routeing and siting for any strategic option taken forward as a preferred option(s).

5.1.16 The options in the following sections of this report have been taken forward in this document as they meet the need case and have been selected using the methodology set out above.

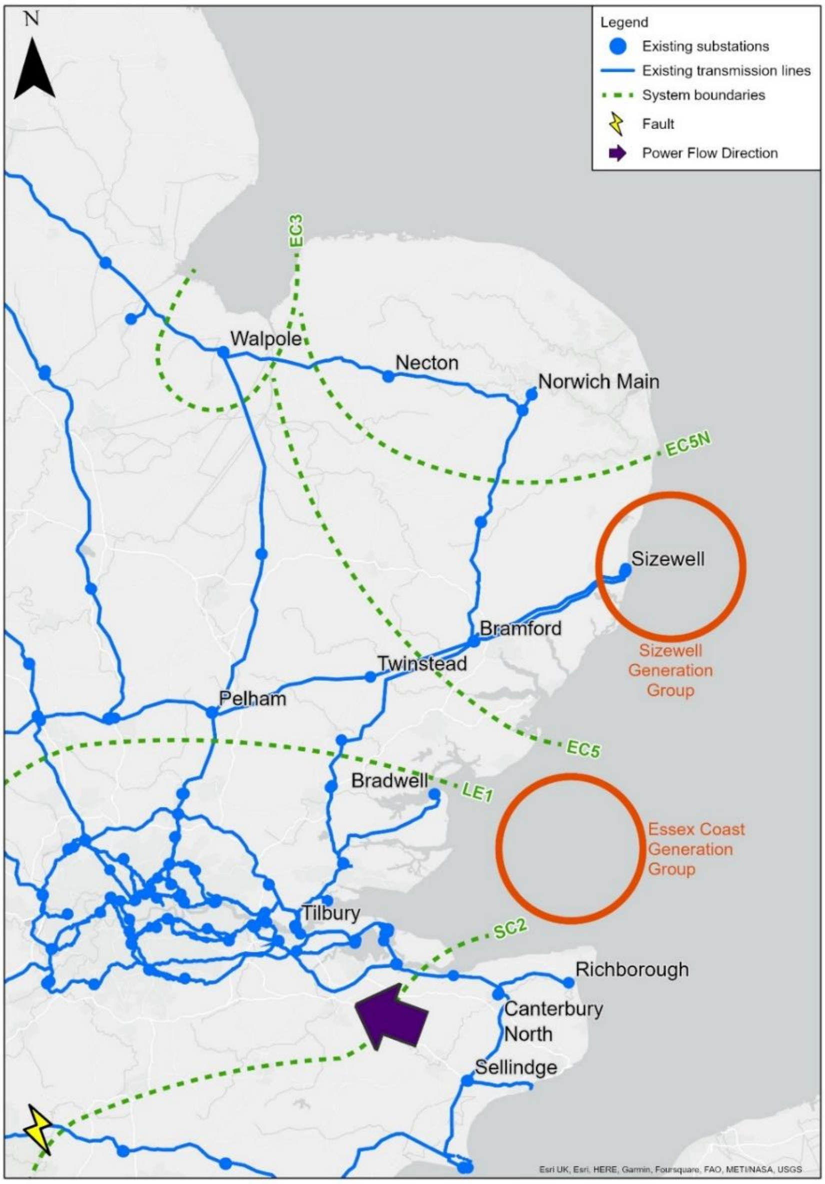
6. Strategic options overview

6.1 Introduction

6.1.1 As described in Section 3 above, the transmission system needs reinforcement to ensure ongoing SQSS compliance as the volume of generation connecting in the area increases.

6.1.2 Figure 6.1 below shows the transmission network in the East Anglia and the South East region including all works completed to maximise existing system capability including Bramford to Twinstead new overhead line, due for commissioning in 2028, which is required to meet the needs of earlier connections of generation and interconnectors.

Figure 6.1 – Considered East Anglia and South East Transmission System and system boundaries



6.2 Connection options considered for detailed appraisal

6.2.1 In line with Our Approach to Consenting, this Strategic Options Report is designed to test the assumptions and interim conclusions made to date based on the latest information available.

6.2.2 A combination of options is required to resolve individual power constraints across the boundaries indicated in Figure 6.1.

6.2.3 Firstly, solutions are required to resolve capacity shortfalls across EC5, EC5N, LE1 and Sizewell Generation Group combined. These boundaries are partly resolved by other reinforcements being developed in East Anglia, with the current preferred solution being the Norwich to Tilbury project. Further detail on the options appraisal process for this project can be found in the Norwich to Tilbury Strategic Options Backcheck and Review published in June 2023[9]. The Bramford to Twinstead reinforcement, for which development consent is currently being sought from the Secretary of State, also contributes to increasing capacity across EC5.

6.2.4 Secondly, boundary SC2 causes an additional impact due to the need to support energy flow directly into the area for high interconnector export scenarios seen consistently in FES. This means that the Kent area including SC2 requires additional connection capacity to remain compliant with the NETS SQSS.

6.2.5 This report considers the options to resolve, in combination with Norwich to Tilbury (or a variant of equivalent capability), the need for power transfer between East Anglia and the South East of England, resolving capacity shortfalls across SC2, as well as EC5, LE1 and the Sizewell Generation Group.

6.2.6 For the reasons set out in Section 3, all options connect in the Sizewell area.

6.3 Options for strategic options assessment

6.3.1 This report assesses the options (SL1, SL2, SL3 and LL1) identified in the CPRSS. This is considered to be a robust range of credible options. No other options have been identified since the CPRSS was completed.

6.3.2 To enable power transfer from the Sizewell Generation Group, it remains necessary for all options to have a northern connection point in the Sizewell area to resolve the need case set out in Section 3.

6.3.3 Following technical and benefits filtering, the CPRSS excluded the onshore option LL1 from environmental and socio-economic appraisal. This strategic options assessment exercise includes LL1 for completeness, to assess whether the option offers any benefit over the offshore options SL1, SL2 and SL3.

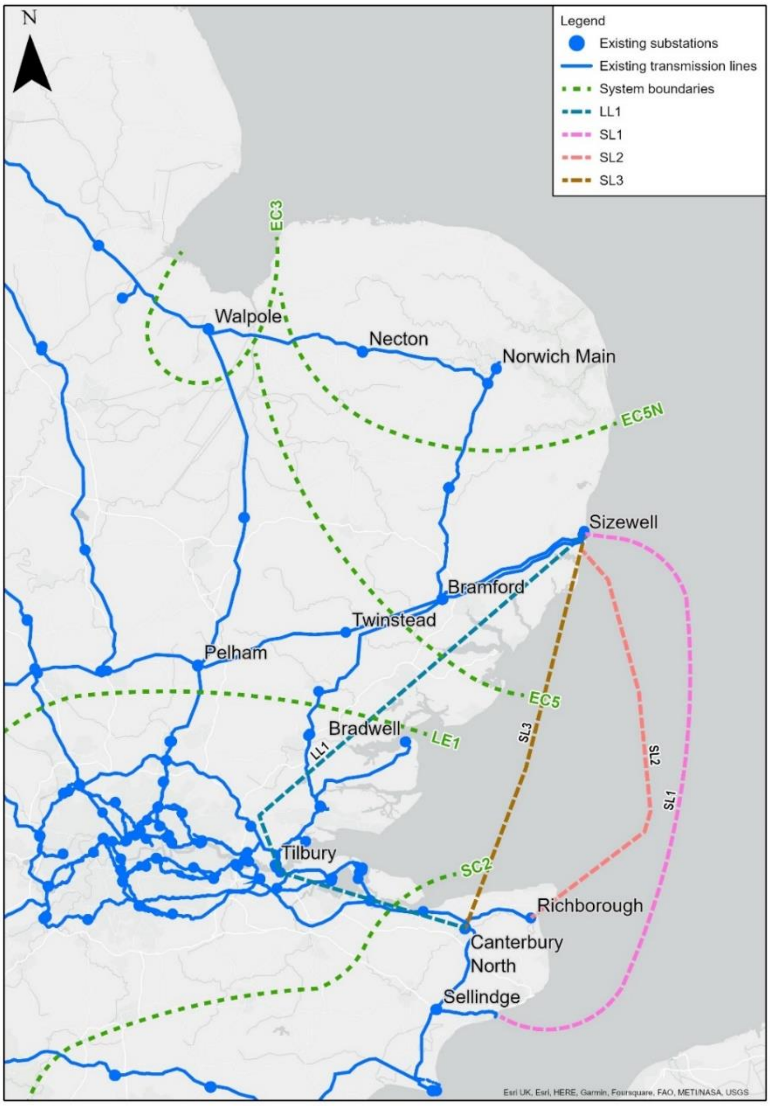
6.3.4 The options considered to resolve the need case requirements are:

- SL1 – Sizewell Area to Sellindge subsea approx. 180 km;

[9] https://www.nationalgrid.com/electricity-transmission/document/149281/download

- SL2 – Sizewell Area to Richborough subsea approx. 120 km;
- SL3 – Sizewell Area to Canterbury subsea approx. 120 km;
- LL1 – Sizewell Area to Canterbury onshore approx. 220 km.

Figure 6.2 – Connection options



6.4 Updated costs

6.4.1 The costs for both onshore and offshore options included within this report have been updated to account for the latest information and are provided in a 2020/2021 price base. For ease of reference, we have also included the customer connection costs within the total. The methodology we have used is set out in Appendix D. This report supersedes any information provided prior to October 2023.

6.5 Study areas

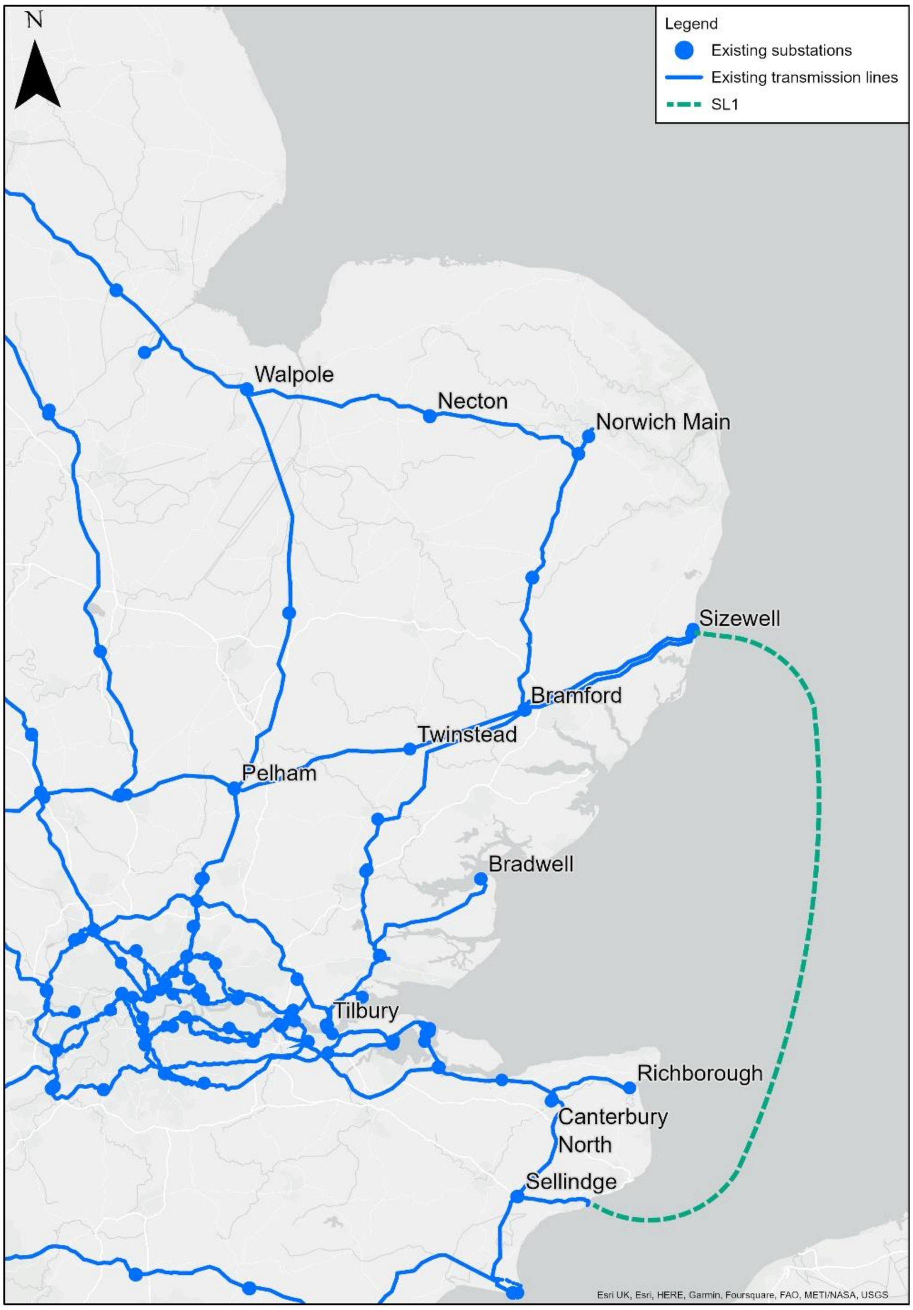
6.5.1 Plans showing the onshore study areas used for the environmental and socio-economic appraisal are included in Appendix G.

7. SL1 – Sizewell Area to Sellindge

7.1 Introduction

7.1.1 Strategic option SL1 involves a new 520 kV HVDC 2000 MW mostly subsea transmission connection between a new substation in the geographical vicinity of Sizewell and new substation in the geographical vicinity of Sellindge, a distance of approximately 180 km as shown in Figure 7.1 below.

Figure 7.1 – Option SL1 Sizewell area to Sellindge



7.2 Environmental appraisal

Onshore

7.2.1 The Study Area is characterised by a number of sensitive receptors, including international and nationally designated sites for nature conservation and heritage.

7.2.2 In Kent, the Study Area includes the World Heritage Site of Canterbury Cathedral, St. Augustine's Abbey and St. Martin's Church, all located within Canterbury. There are also Scheduled Monuments and listed buildings. The Kent Downs Area of Outstanding Natural Beauty (AONB) is a nationally designated landscape that also falls within this Study Area. With careful route alignment/siting/consideration of routeing/trenchless techniques, impacts are likely to be avoidable.

7.2.3 The Kent onshore Study Area contains international and nationally designated sites such as Ramsar sites, Special Protection Areas (SPA) and Special Areas of Conservation (SAC). The assessment identifies two potential routes from Sellindge to the coast where fewer ecologically designated sites would be impacted: one from Sellindge to Walmer/Deal (avoiding Alkham-Lydden-Swingfield Woods) and another from Sellindge to Hythe (avoiding Lympne Escarpment).

7.2.4 Coastal designated sites include the Swale SPA and Thanet Coast and Sandwich Bay SPA. When considered individually these designations are avoidable, however, when considered in-combination with other constraints avoidance is unlikely. Consideration of timing, especially related to breeding and overwintering bird populations, is a principal concern in cable installation.

7.2.5 The south of the Kent onshore Study Area features a band of higher ground stretching between Challock in the west and Dover in the East, while the remaining land area is relatively flat. There are three flood storage areas located at Ashford, Hythe and Sellindge. The extension/modification of the existing 400 kV Substation at Sellindge is located in Flood Zone 3, and therefore opportunities to construct supporting infrastructure outside of the flood zone should be investigated.

7.2.6 In Suffolk, coastal and southern half of the onshore study area fall within the Suffolk Coast and Heaths Area of Outstanding Natural Beauty, with the Suffolk Heritage Coast extending along the entire coastline. The existing Sizewell substation falls under both designations. There are also Scheduled Monuments and listed buildings.

7.2.7 In addition to heritage and landscape designations, there are also a number of international and nationally designated sites for nature conservation, including Minsmere-Walberswick Ramsar and SPA, Minsmere-Walberswick Heaths and Marshes SAC, Sizewell Marshes SSSI, and Sandling SPA and Leiston-Aldeburgh SSSI.

7.2.8 The Suffolk onshore Study Area is sparsely populated with the small settlements of Leiston, Knodishall, Friston, Blaxhall, Tunstall, Chillesford and Sudbourne. Several proposed developments are in the Sizewell area, including the Sizewell C nuclear power station and onshore connections for the East Anglia One North and Two Offshore Wind Farms, which includes a group of proposed new substations at Friston.

7.2.9 Whilst the onshore study area at Sizewell is sparsely populated and it is likely that significant effects on the ecological designations could be either avoided or mitigated, a large proportion of the study area is designated as AONB, and therefore setting effects of a converter station and/or substation are likely to be a principal consideration.

Offshore

7.2.10 There are ten Marine Character Areas (MCAs), seven protected wreck sites, and several other ecologically valuable designated sites in the coastal/marine part of the study area, including internationally important coastal/intertidal habitats supporting diverse bird populations. Notable designations include the Outer Thames Estuary SPA, Margate and Long Sands SAC, the Southern North Sea SAC and Goodwin Sands and Kentish Knock Marine Conservation Zones (MCZ).

7.2.11 The Southern North Sea SAC, designated for harbour porpoises, overlaps with, and extends to the north and east of the study area where cables may be routed through. Marine mammal European Protected Species (EPS), such as grey and harbour seals, have an increased presence in the area, and interactions with installation/maintenance activities have potential to occur.

7.2.12 To reduce potential impacts, careful routeing of the infrastructure to avoid protected sites and associated habitats is recommended. Avoiding offshore sites (SAC/MCZ) where practicable, considering alternative construction methods (e.g., trenchless construction) across intertidal habitats, and timing construction activities to avoid sensitive periods for bird species are other measures to minimise ecological impacts.

7.2.13 Although the proposed landfall and cable route has the potential to impact designated sites (including Margate and Long Sands SAC, Southern North Sea SAC, coastal SSSI's, Thanet Coast MCZ) and protected species, implementing best practices and alternative construction methods would help to mitigate these impacts.

7.2.14 Intertidal designations including the Swale SPA, Thanet Coast and Sandwich Bay SPA, Orfordness NNR and Minsmere-Walberswick SPA are expected to be unavoidable. However, through appropriate routeing and implementing mitigation measures, significant adverse effects can be avoided. The Swale and Thanet Coast and Sandwich Bay SPA sites are designated for both over wintering and breeding bird populations, therefore the timing of cable installation will be a principal consideration in determining routes within or in close proximity to these sites.

7.2.15 The Outer Thames Estuary is a dynamic environment with sediment fluctuations. Mobile sediment may cause cable spanning or over-burial issues. Cable protection measures will likely be necessary where cable spanning is a concern. However, in some locations, these measures might lead to solutions that cannot be granted consent, requiring mitigation through detailed routeing. Whilst the Outer Thames Estuary SPA is likely to be unavoidable it is likely that impacts could be managed through timing and construction practice and therefore this site is not considered to be a barrier to future development.

7.3 Socio-economic appraisal

Onshore

7.3.1 Within the Kent region of the study area, seven urban settlements were identified including Herne Bay, Canterbury, Deal, Margate, Ashford, Folkestone and Whitefield (Dover). In the north of the study area in Suffolk, the land is sparsely populated with the small settlements of Leiston, Knodishall and Friston. Temporary adverse impacts could arise during construction if the cable route is situated close to settlements due to impacts of noise, air quality and construction traffic. In addition, the converter stations, if required, also have the potential for adverse visual effects which are set out in the landscape and visual appraisal, as well as noise and air quality if close to property.

7.3.2 There is the potential for temporary adverse effects on tourism and recreation facilities during construction. The routeing of a cable would need to be carefully situated to avoid areas popular with tourists, and be mindful of the temporary disturbance caused for people using the area for recreational activities. To reduce socio-economic impacts, it is recommended to lay the cables to the northern shoreline to reduce socio-economic impacts due to fewer urban regions in the north than the east and the northern shoreline being closer, subsequently resulting in a likely reduced construction programme. In addition, routeing onshore to Sizewell substation should look to be as direct and short as possible.

7.3.3 There is the potential for temporary adverse impacts on agricultural land during construction, and there is the potential for permanent loss associated with converter stations (if required). Options to avoid Best and Most Versatile (BMV) land should be sought if progressed. Standard best practice guidelines should be followed to reinstate agricultural land following construction.

7.3.4 Where crossings are required, temporary closures of roads/railways may be required during construction. Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice to the public who use the roads should these be temporary closed during construction.

Offshore

7.3.5 The primary marine uses within the offshore area of the study area include shipping and navigation and fishing, with the most significant Port area being the Port of London Authority (PLA). However, the Port of Margate, is also present within the study area and the dredged channel for the Port of Felixstowe extends into this study area. The main shipping channels into the Port of London include Princes, Black and Borrow Deep which converge into the Yantlet Channel that extends up the inner Thames. Due to the shallow and mobile nature of the seabed within the Thames Estuary a number of these channels are dredged to facilitate access for the larger vessels along with channels into both Margate and Felixstowe. Shipping channels, particularly those which are dredged are a primary determining factor as dredging could result in the exposure and potential damage to the cable. The Pollard Marine Farm is also located within the study area off the north Kent coast at Whitstable which is likely to be a limiting factor to marine cable routeing.

7.3.6 Outside of the main shipping channels, the shallow waters of Kentish Flats, Goodwin Sands, Gunfleet and Sunk Sand are a consideration for installation methods and in particular any rock placement required for crossings of other infrastructure. This is likely to be a determining factor where any rock placement would result in a reduction of water depth of 5% or more which is generally considered to be unacceptable. Within the study area, it is unlikely cable crossings could be avoided within the shallow waters of Kentish Flats as well as avoiding Margate and Long Sands SAC, however it may be possible to avoid shallow water crossings at Goodwin Sands. Marine infrastructure present includes the Kentish Flats, Thanet and London Array, Greater Gabbard and Galloper offshore wind farms and export cables, BritNed and NemoLink interconnectors and the proposed NeuConnet and GridLink Interconnectors. Whilst the offshore wind farms are avoidable, it is unlikely that crossings of cables, could be avoided entirely. As discussed above, where these crossings cannot be avoided in shallow waters such as

Kentish Flats, the potential decrease in water depth is regarded as a principle consideration.

7.3.7 Whilst (with the exception of the Outer Thames Estuary SPA and cable crossings) most constraints in the marine study area are avoidable when considered in isolation, when considered in combination avoidance may not be possible. Due to the sensitives around Margate and Long Sands SAC, because it is unlikely that the crossing of other existing and proposed infrastructure cannot be avoided within the site, this site divides the marine study areas into two. The site could be avoided to the west, however, this would require the potential crossing of London Array export cables in shallow water and the crossing of a number of the shipping channels into the Port of London. Liaison with the PLA would be required to confirm the feasibility of a route through this part of the outer Thames Estuary. The site could also be avoided to the east although this would require a route through the Southern North Sea SAC and potentially some interaction with Goodwin Sands MCZ.

7.3.8 An onshore connection into Sellindge can be made via either the north, east or south Kent coasts within this study area with the latter being the least constrained and whilst resulting in a longer marine route the onshore connection would be shorter. Sellindge substation itself is located adjacent to other similar infrastructure and adjacent to major transport routes therefore it is likely that the siting of converter station in this locality would be in keeping with the existing infrastructure.

7.3.9 Whilst the onshore study area at Sizewell is sparsely populated and it is likely that significant effects on the ecological designations could be either avoided or mitigated, a large proportion of the study area is designated as AONB. As a result, setting effects of a converter station and/or substation are likely to be a principal consideration. In addition, there is a significant amount of proposed development in the vicinity of Sizewell and the settlements of Leiston and Friston. These plans must be considered in combination to ensure that there is a balance of development in this area.

7.4 Technical scope and costs

7.4.1 Technical analysis of option SL1 is as follows:

- This option to connect a 180 km circuit between Sizewell Area and Sellindge area allows transfers of energy between Suffolk and Kent, providing a transmission connection to the east of London.
- As this option is only required to provide 2000 MW (2 GW) of capacity between Suffolk and Kent the HVDC option only requires a single HVDC link. The AC option however without the ability to control power flow along the circuit would require to be of 6380 MW double circuit capacity.

7.4.2 As set out in Section 5, we undertook a cost evaluation of the following two technologies for subsea options evaluation.

- 400 kV AC subsea cable
- 525 kV HVDC subsea cable

7.4.3 Option SL1 requires the following transmission works to satisfy the requirements of the SQSS.

New Circuit requirements

- AC subsea connections circuit options use Med-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6380 mega volt amperes (MVA) of a distance of 180 km; or
- HVDC connection options use 525 kV 2 GW voltage source links, which would require a convertor station at each end, similar in size to a large warehouse. In this case a 2000 MW (2 GW) connection would require two convertor stations in total, with up to two of the convertors located at the New Walpole Substation;
- Subsea HVDC cables totalling 180 km.

National Grid Substation Works

- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Sizewell
- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Sellindge

7.4.4 Table 7.1 below sets out the capital costs for option SL1 considering substation works and each technology option.

Table 7.1 – SL1 capital cost summary

Item	**Need**	**SL1 Capital Cost**	
Substation Works	Facilitate generation and connect new circuits	£249.0m	
New Circuits		**AC Subsea Cable (6380 MW)**	**HVDC Subsea (2000 MW)**
New Circuit 180 km	New Circuit across EC5 and SC2	£5,468.2m	£1,090.6m
Total Capital Cost		**£5,717.2m**	**£1,339.6m**

7.4.5 Table 7.2 below sets out the lifetime cost for the new circuit options, the lifetime costs are different for each circuit technology and are included as a differentiator between technologies. These costs are calculated using the methodology described in Appendix D.

Table 7.2 – SL1 Lifetime cost summary

Land Based option	SL1 AC Subsea Cable (6380 MW)	SL1 HVDC Subsea (2000 MW)
Capital Cost of New Circuits	£5,468.2m	£1,090.6m
NPV of cost of losses over 40 years	£364.5m	£157.1m
NPV of operation & maintenance costs over 40 years	£31.4m	£57.6m
Lifetime cost of new circuits	**£5,846m**	**£1,305m**

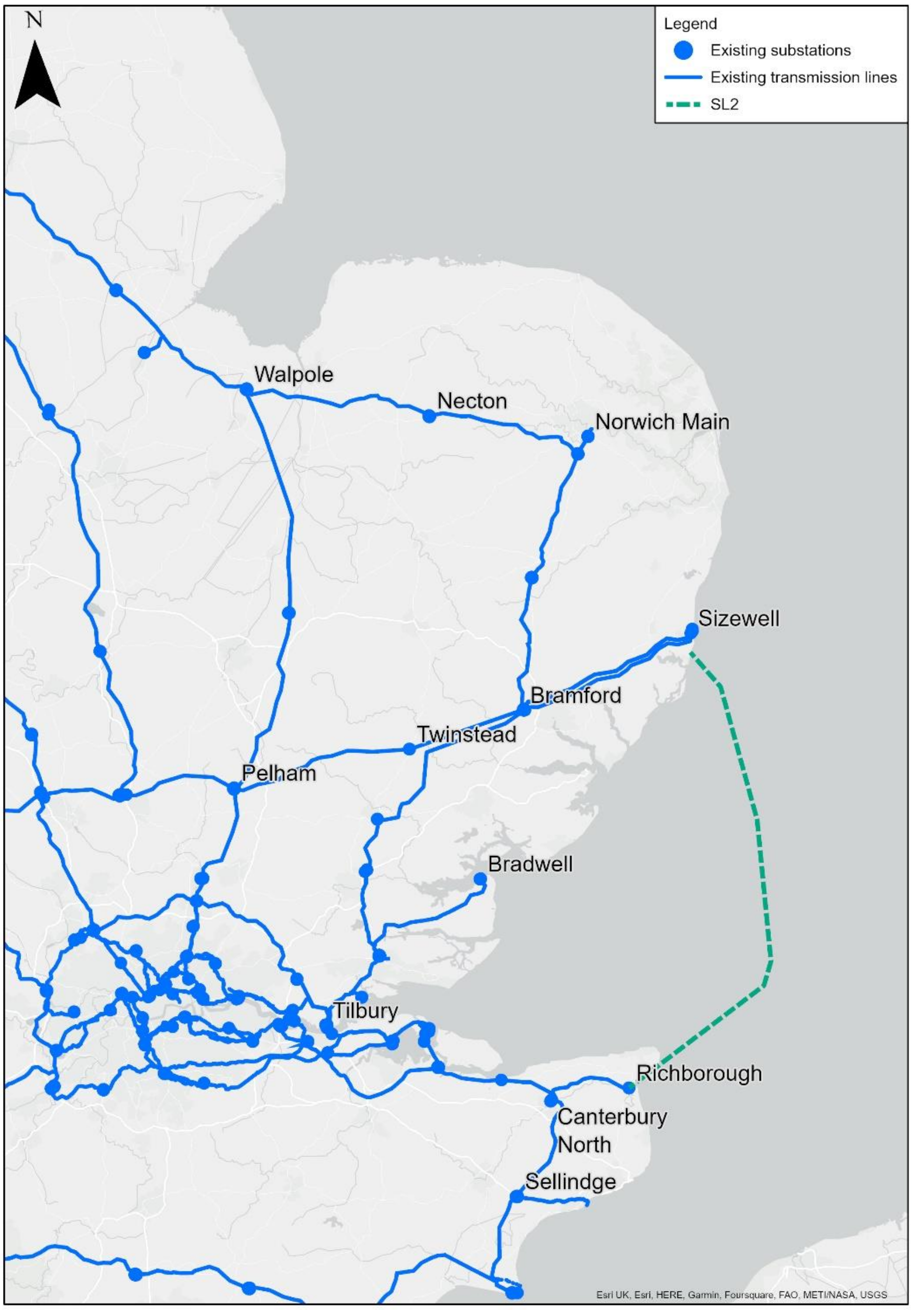
7.4.6 From the environmental and technical appraisal considered, alongside capital and circuit lifetime costs, the preferred option for SL1, is a 2000 MW (2 GW) HVDC link connecting between Sizewell and Sellindge areas, connecting to new substations at each end. In light of this analysis our starting presumption for further development of this option should it be selected, would be for a majority HVDC subsea connection.

8. SL2 – Sizewell Area to Richborough

8.1 Introduction

8.1.1 Strategic option SL2 involves a new 520 kV HVDC 2000 MW transmission connection between a new substation in the geographical vicinity of Sizewell and new substation in the geographical vicinity of Richborough, a distance of approximately 120 km shown in Figure 8.1.

Figure 8.1 – Option SL2 Sizewell Area to Richborough area



8.2 Environmental appraisal

Onshore

8.2.1 There are a number of sensitive receptors located within the Study Area which include international and nationally designated sites for nature conservation and heritage.

8.2.2 Within Kent, notably, Richborough Substation is located on the east Kent coast within Richborough Energy Park. The area around the substation is sparsely populated and the existing substation is surrounded by similar infrastructure.

8.2.3 The majority of the coastline within the Kent Onshore Study Area at Richborough is designated within the Thanet Coast and Sandwich Bay area, which includes SPA, Ramsar, SAC, SSSI and NNR sites. Where there are gaps in these designations at Deal and Ramsgate, the settlement pattern is much denser. The Stodmarsh designated sites extend into the west of the onshore Study Area. Scheduled Monuments and listed buildings contribute to the area's heritage, with the Kent Area of Outstanding Natural Beauty (AONB) situated to the south of Canterbury. With careful route alignment, siting, consideration of routeing, trenchless techniques, potential significant impacts are likely to be avoidable.

8.2.4 Richborough substation partially falls within Flood Zones 2 and 3. As a result, extending this substation is likely to require an exception test to demonstrate that there are no suitable alternatives. There are also large areas of Flood Zone within the Study Area associated with the low-lying coastal marshes and the River Stour.

8.2.5 The siting of a converter station close to the existing substation aligns well with existing infrastructure in this locality.

8.2.6 Within the Suffolk region of the study area, seven urban settlements were identified including Leiston, Knodishall and Friston, Blaxhall, Tunstall, Chillesford and Sudbourne. Several proposed developments are in the Sizewell area, including the Sizewell C nuclear power station and onshore connections for the East Anglia One North and Two Offshore Wind Farms, which includes a group of proposed new substations at Friston. The coastal and the majority of the southern half of the onshore Study Area fall within the Suffolk Coast and Heaths Area of Outstanding Natural Beauty, with the Suffolk Heritage Coast extending along the entire coastline. The existing Sizewell substation falls under both designations.

8.2.7 Whilst the onshore study area at Sizewell is sparsely populated and it is likely that significant effects on the ecological designations could be either avoided or mitigated, a large proportion of the study area is designated as AONB, and therefore setting effects of a converter station and/or substation are likely to be a principal consideration.

Offshore

8.2.8 There are seven Marine Character Areas (MCAs), seven protected wreck sites, and several other ecologically valuable designated sites in the coastal/marine part of the study area, including internationally important coastal/intertidal habitats supporting diverse bird populations. Notable designations include the Outer Thames Estuary SPA, Margate and Long Sands SAC, the Southern North Sea SAC and Goodwin Sands and Kentish Knock Marine Conservation Zones (MCZs).

8.2.9 The Southern North Sea SAC, designated for harbour porpoises, overlaps with, and extends to the north and east of the study area where cables may be routed through.

Marine mammal European Protected Species (EPS), such as grey and harbour seals, have an increased presence in the area, and interactions with installation/maintenance activities have potential to occur.

8.2.10 The proposed landfall and cable route has the potential to impact protected species and designated sites including Margate and Long Sands SAC, Southern North Sea SAC, coastal SSSIs and Thanet Coast MCZ. Notably, there are sensitivities surrounding Margate and Long Sands SAC as there is potential for permanent habitat loss.

8.2.11 To reduce potential impacts, careful routeing of the infrastructure to avoid protected sites and associated habitats is recommended. Avoiding offshore sites (SAC/MCZ) where practicable, considering alternative construction methods (e.g., trenchless construction) across intertidal habitats, and timing construction activities to avoid sensitive periods for bird species are other measures to minimise ecological impacts.

8.2.12 The assessment concludes that the western part of Margate and Long Sands SAC is avoidable, and the two offshore MCZs are also avoidable when considered in isolation.

8.2.13 Intertidal designations including the Swale SPA, Thanet Coast and Sandwich Bay SPA, Orfordness NNR and Minsmere-Walberswick SPA are expected to be unavoidable. However, through appropriate routeing and implementing mitigation measures, significant adverse effects can be avoided. The Swale designated sites are designated for both over wintering and breeding bird populations, therefore the timing of cable installation will be a principle consideration in determining routes within or in close proximity to these sites.

8.2.14 The Outer Thames Estuary is a dynamic environment with sediment fluctuations. Mobile sediment may cause cable spanning or over-burial issues. Cable protection measures will likely be necessary where cable spanning is a concern. However, in some locations, these measures might lead to solutions that cannot be granted consent, requiring mitigation through detailed routeing. Whilst the Outer Thames Estuary SPA is likely to be unavoidable, it is likely that impacts could be managed through timing and construction practice and therefore this site is not considered to be a barrier to future development.

8.3 Socio-economic appraisal

Onshore

8.3.1 In the south of the study area in Kent, there are four main urban settlements including Ramsgate, Herne Bay, Deal and Margate. These urban settlements include high density populated areas. In the north of the study area in Suffolk, the land is sparsely populated with the small settlements of Leiston, Knodishall and Friston. Blaxhall, Tunstall, Chillesford and Sudbourne. Temporary adverse impacts could arise during construction if the cable route is situated close to settlements due to impacts of noise, air quality and construction traffic. In addition, the converter stations also have the potential for adverse visual effects which are set out in the landscape and visual appraisal, as well as noise and air quality if close to property.

8.3.2 There is the potential for temporary adverse effects on tourism and recreation facilities during construction. The routeing of a cable would need to be carefully situated to avoid areas popular with tourists, and be mindful of the temporary disturbance caused for people using the area for recreational activities. To reduce socio-economic impacts it is recommended to lay the cables to the northern shoreline due to fewer urban regions in the north than the east and the northern shoreline being closer, subsequently resulting in a likely reduced construction programme. In addition, routeing onshore to Sizewell substation should look to be as direct and short as possible.

8.3.3 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with converter stations (if required) but this is unlikely to be significant. Standard best practice guidelines should be followed to reinstate agricultural land following construction.

8.3.4 Where crossings are required, temporary closures of roads/railways may be required during construction. Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice to the public who use the roads should these be temporary closed during construction.

Offshore

8.3.5 Within the study area in the outer Thames there are extensive areas outside of the main shipping channels which are shallow, principally Kentish Flats, Goodwin Sands, Gunfleet and Sunk Sand. While these shallow waters don't prevent the installation of transmission infrastructure, they do factor into the choice of installation methods, especially concerning any necessary rock placement for crossings of other infrastructure. This is likely to be a determining factor where any rock placement would result in a reduction of water depth of 5% or more which is generally considered to be unacceptable. Within the study area it is unlikely cable crossings could be avoided within the shallow waters of Kentish Flats, as well as avoiding designated ecological sites, however it may be possible to avoid shallow water crossings at Goodwin Sands.

8.3.6 The primary marine uses within the offshore area of the study area include shipping and navigation and fishing, with the most significant Port area being the Port of London Authority (PLA). However, the Port of Margate, is also present within the study area and the dredged channel for the Port of Felixstowe extends into this study area. The main shipping channels into the Port of London include Princes, Black and Borrow Deep which converge into the Yantlet Channel that extends up the inner Thames. Due to the shallow and mobile nature of the seabed within the Thames Estuary, a number of these channels are dredged to facilitate access for the larger vessels along with channels into both Margate and Felixstowe. Shipping channels, particularly those which are dredged, are considered to be a primary determining factor as dredging could result in the exposure and potential damage to the cable.

8.3.7 Within the study area, other marine infrastructure is present including Kentish Flats, Thanet and London Array, Greater Gabbard and Galloper offshore wind farms and export cables, BritNed and NemoLink interconnectors and the proposed NeuConnect and GridLink Interconnectors. Whilst the offshore wind farms are avoidable, it is unlikely that crossings of cables, could be avoided entirely. As discussed above, where these crossings cannot be avoided in shallow waters such as Kentish Flats, the potential decrease in water depth is regarded as a principle consideration. Whilst (with the exception of the Outer Thames Estuary SPA and cable crossings) most constraints in the marine study area are avoidable when considered in isolation, when considered in combination, avoidance may not be possible. Due to the sensitives surrounding Margate and Long Sands SAC, especially considering that the crossing of other existing and proposed infrastructure cannot be easily avoided within the site, this site splits the marine study areas into two. While avoiding the site to the west is an option, it would involve potentially crossing London Array export cables in shallow water and navigating several shipping channels leading into the Port of London. Liaison with the PLA would be required to confirm the feasibility of a route through this part of the outer Thames Estuary. The site could also be avoided to the east although this would require a route through the Southern North Sea SAC and potentially some interaction with Goodwin Sands MCZ.

8.3.8 In Kent, the onshore connection at Richborough is constrained by the Thanet Coast and Sandwich Bay designated sites. These sites, designated for breeding and overwintering bird populations, and the denser settlement pattern along the coastline, are likely to be unavoidable. Whilst the onshore study area at Sizewell is sparsely populated and it is likely that significant effects on the ecological designations could be either avoided or mitigated, a large proportion of the study area is designated as AONB. Therefore, setting effects of a converter station and/or substation are likely to be a principal consideration. In addition, there is a significant amount of proposed development in the vicinity of Sizewell and the settlements of Leiston and Friston. These plans must be considered in combination to maintain balanced development in the area.

8.4 Technical scope and costs

8.4.1 Technical analysis of option SL2 is as follows:

- This option to connect a 120 km circuit between Sizewell Area and Richborough area allows transfers of energy between Suffolk and Kent, providing a transmission connection to the east of London.
- As this option is only required to provide 2000 MW (2 GW) of capacity between Suffolk and Kent the HVDC option only requires a single HVDC link. The AC option however without the ability to control power flow along the circuit would require to be of 6380 MW double circuit capacity

8.4.2 As set out in Section 5, we undertook a cost evaluation of the following two technologies for subsea options evaluation.

- 400 kV AC subsea cable
- 525 kV HVDC subsea cable

8.4.3 Option SL2 requires the following transmission works to satisfy the requirements of the SQSS.

New Circuit requirements

- AC subsea connections circuit options use Med-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6380 mega volt amperes (MVA) of a distance of 120 km; or
- HVDC connection options use 525 kV 2 GW voltage source links, which would require a convertor station at each end, similar in size to a large warehouse. In this case a 2000 MW (2 GW) connection would require two convertor stations in total, with up to two of the convertors located at the New Walpole Substation
- Subsea HVDC cables totalling 120 km

National Grid Substation Works

- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Sizewell

- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Richborough

8.4.4 Table 8.1below sets out the capital costs for option SL2 considering substation works and each technology option.

Table 8.1 – SL2 capital cost summary

Item	Need	SL2 Capital Cost	
Substation Works	Facilitate generation and connect new circuits	£249.0m	
New Circuits		**AC Subsea Cable (6380 MW)**	**HVDC Subsea (2000 MW)**
New Circuit 120 km	New Circuit across EC5 and SC2	£3,627.7m	£905.2m
Total Capital Cost		**£3,876.7m**	**£1,154.2m**

8.4.5 Table 8.2 below sets out the lifetime cost for the new circuit options, the lifetime costs are different for each circuit technology and are included as a differentiator between technologies. These costs are calculated using the methodology described in Appendix D.

Table 8.2 – SL2 lifetime cost summary

Land Based option	SL2 AC Subsea Cable (6380 MW)	SL2 HVDC Subsea (2000 MW)
Capital Cost of New Circuits	£3,627.7m	£905.2m
NPV of cost of losses over 40 years	£224.9m	£157.1m
NPV of operation & maintenance costs over 40 years	£20.4m	£57.5m
Lifetime cost of new circuits	**£3,873m**	**£1,120m**

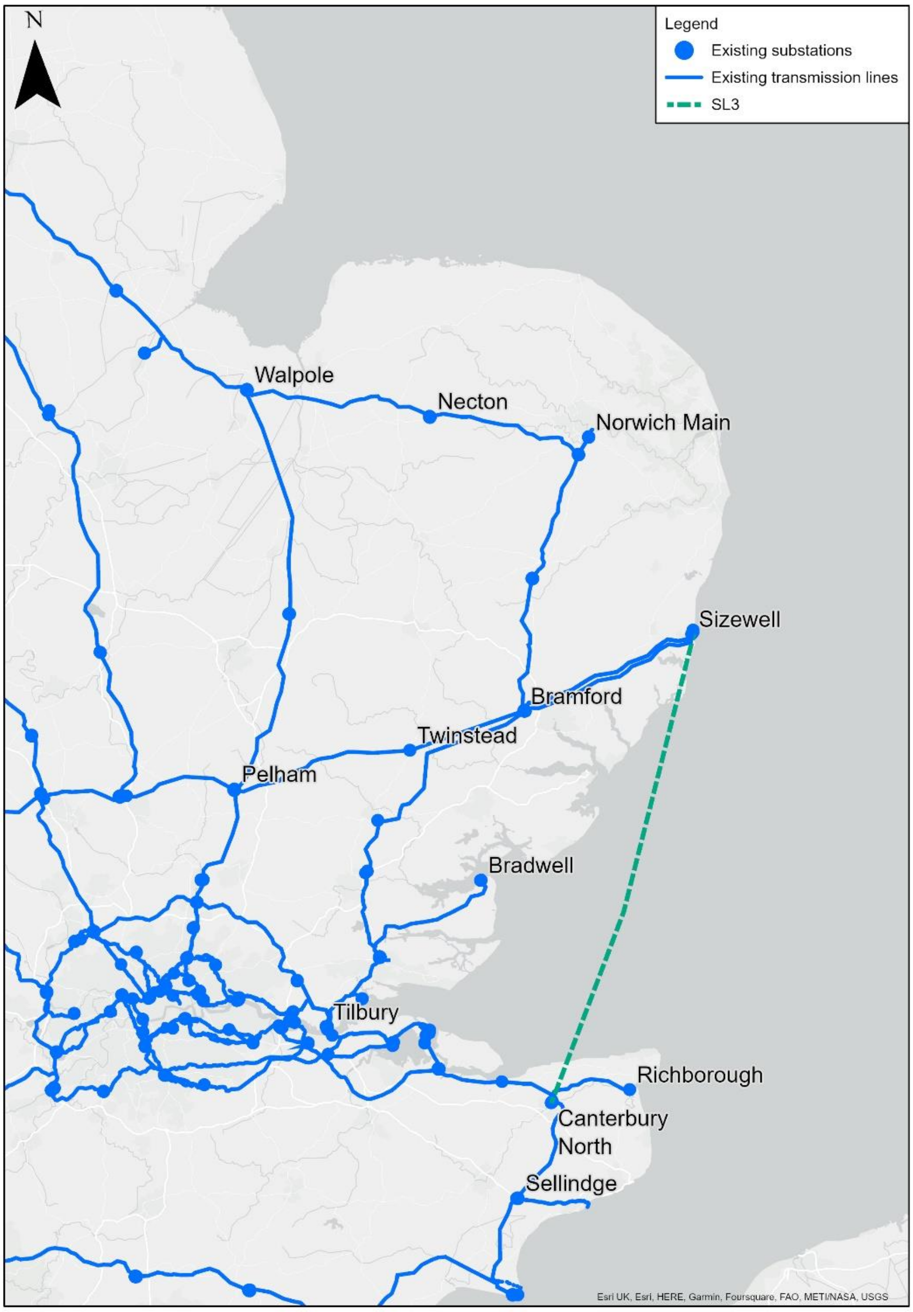
8.4.6 From the environmental and technical appraisal considered, alongside capital and circuit lifetime costs, the preferred option for SL2, is a 2000 MW (2 GW) HVDC link connecting between Sizewell and Richborough areas, connecting to new substations at each end. In light of this analysis our starting presumption for further development of this option should it be selected, would be for a majority HVDC subsea connection.

9. SL3 – Sizewell Area to Canterbury

9.1 Introduction

9.1.1 Strategic option SL3 involves a new 520 kV HVDC 2000 MW transmission connection between a new substation in the geographical vicinity of Sizewell and new substation in the geographical vicinity of Canterbury. a distance of approximately 120 km shown in Figure 9.1.

Figure 9.1 – Option SL3 Sizewell Area to Canterbury area



9.2 Environmental appraisal

Onshore

9.2.1 There are a number of sensitive receptors located within the study area which include international and nationally designated sites for nature conservation and heritage.

9.2.2 In Kent, the Study Area includes the World Heritage Site of Canterbury Cathedral, St. Augustine's Abbey and St. Martin's Church, all located within Canterbury. There are also Scheduled Monuments and listed buildings. The Kent Downs AONB is a nationally designated landscape that also falls within this Study Area to the South of Canterbury. With careful route alignment, siting, consideration of routeing, and trenchless techniques, impacts on heritage and landscape receptors are likely to be avoidable or reduced.

9.2.3 The study area contains international and nationally designated sites such as Ramsar, SPA and SAC. A notable site close to the potential substations is an area of woodland (which includes Ancient Woodland) positioned to the west and north of Canterbury. This area adjoins the Blean complex SAC and West Blean and Thornden Woods Site of Special Scientific Interest (SSSI). There is limited opportunity to avoid all three designations if a northern landfall is made, particularly when considered in conjunction with other constraints. Furthermore, the presence of the Stodmarsh Complex of protected sites to the east of Canterbury combined with existing settlement patterns, poses potential constraints on route options.

9.2.4 Coastal designated sites include the Swale and Thanet Coast and Sandwich Bay. When considered individually these designations area avoidable, however, when considered in combination with other constraints avoidance is unlikely. The former of these designations is designated for both breeding and over wintering populations of bird species therefore the timing of cable installation is considered to be a principal consideration.

9.2.5 There are two substations within Canterbury which are located within Flood Zone 2 (CANT4) and 3 (CANT1). The extension of Canterbury substation would therefore be constructed within a Flood Zone and would require an exception test to demonstrate no suitable alternatives. However as this is an existing substation this is unlikely to be a significant constraint. Due to the extent of development around Canterbury Substation there are limited opportunities to site a converter station in proximity to the existing subtstations.

9.2.6 Within the Suffolk region of the study area, three urban settlements were identified including Leiston, Knodishall and Friston. Several proposed developments are in the Sizewell and surrounding area, including the proposed Sizewell C nuclear power station and the onshore connections for the East Anglia One North and Two Offshore Wind Farms, which includes a group of proposed new substations at Friston.

9.2.7 Onshore at Sizewell, Sandlings SPA and the Alde-Ore and Butley Estuaries Ramsar, SPA and SAC is located in the south of the Study Area and the Minsmere-Walberswick Ramsar, SPA and SAC in the north. A large proportion of which is also designated as a Royal Society for the Protection of Birds (RSPB) reserve, as well as the Aldeburgh to Leiston SSSI. The coastal and the majority of southern half of the onshore Study Area fall within the Suffolk Coast and Heaths Area of Outstanding Natural Beauty, with the Suffolk Heritage Coast extending along the entire coastline. The existing Sizewell substation falls under both designations.

9.2.8 Whilst the onshore study area at Sizewell is sparsely populated and it is likely that significant effects on the ecological designations could be either avoided or mitigated, a large proportion of the study area is designated as AONB, and therefore setting effects of a converter station and/or substation are likely to be a principal consideration.

Offshore

9.2.9 There are number of designated sites within this study area including the Outer Thames Estuary SPA, Margate Long Sands SAC, the Southern North Sea SAC and Goodwin Sands and Kentish Knock Marine Conservation Zones. Whilst the Outer Thames Estuary SPA is likely to be unavoidable it is likely that impacts could be managed through timing and construction practice and therefore this site is not considered to be a barrier to future development within this study area.

9.2.10 The Southern North Sea SAC is designated for Harbour Porpoise and it is expected that any potential effects could be managed through timing and construction practices. Margate and Long Sands SAC is considered to be a principal consideration due to the potential for permanent habitat loss associated with cable crossings and protection however this site is avoidable. The two offshore MCZs are both avoidable when considered in isolation.

9.2.11 Intertidal designations including the Swale SPA, Thanet Coast and Sandwich Bay SPA, Orfordness NNR and Minsmere-Walberswick SPA are all unlikely to be avoidable but which through appropriate routeing and mitigation a likely significant effect is likely to be avoidable. The Swale designated sites are designated for both over wintering and breeding bird populations therefore the timing of cable installation is likely to be principle consideration in relation to any routes within or in close proximity of these sites.

9.2.12 The Outer Thames Estuary is a highly mobile environment. Mobile sediment is an important consideration as cable spanning or over burial could occur.

9.3 Socio-economic appraisal

Onshore

9.3.1 In the south of the study area in Kent, there are four main urban settlements including Herne Bay, Canterbury, Deal and Margate. These urban settlements include high density populated areas. In the north of the study area in Suffolk, the land is sparsely populated with the small settlements of Leiston, Knodishall and Friston. Temporary adverse impacts could arise during construction if the cable route is situated close to settlements due to impacts of noise, air quality and construction traffic. In addition, the converter stations also have the potential for adverse visual effects which are set out in the landscape and visual appraisal, as well as noise and air quality if close to property.

9.3.2 There is the potential for temporary adverse effects on tourism and recreation facilities during construction. The routeing of a cable would need to be carefully situated to avoid areas popular with tourists and be mindful of the temporary disturbance caused for people using the area for recreational activities. To reduce socio-economic impacts it is recommended to lay the cables to the northern shoreline to reduce socio-economic impacts due to fewer urban regions in the north than the east and the northern shoreline being closer, subsequently resulting in a likely reduced construction programme. In addition, routeing onshore to Sizewell substation should look to be as direct and short as possible.

9.3.3 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with converter stations (if required) but this is unlikely to be significant. Standard best practice guidelines should be followed to reinstate agricultural land following construction.

9.3.4 Where crossings are required, temporary closures of roads/railways may be required during construction. Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice to the public who use the roads should these be temporary closed during construction.

Offshore

9.3.5 The primary marine uses within the offshore area of the study area include shipping and navigation and fishing, with the most significant Port area being the Port of London Authority (PLA). However, the Port of Margate, is also present within the study area and the dredged channel for the Port of Felixstowe extends into this study area. The main shipping channels into the Port of London include Princes, Black and Borrow Deep which converge into the Yantlet Channel that extends up the inner Thames. Due to the shallow and mobile nature of the seabed within the Thames Estuary a number of these channels are dredged to facilitate access for the larger vessels along with channels into both Margate and Felixstowe. Shipping channels, in particular, those which are dredged are considered to be a primary determining factor as dredging could result in the exposure and potential damage to the cable. The Pollard Marine Farm is also located within the study area off the north Kent coast at Whitstable which is likely to be a limiting factor to marine cable routeing.

9.3.6 Outside of the main shipping channels, the shallow waters of Kentish Flats, Goodwin Sands, Gunfleet and Sunk Sand are a consideration for installation methods and in particular any rock placement required for crossings of other infrastructure. This is likely to be a determining factor where any rock placement would result in a reduction of water depth of 5% or more which is generally considered to be unacceptable. Within the study area it is unlikely cable crossings could be avoided within the shallow waters of Kentish Flats as well as avoiding Margate and Long Sands SAC, however it may be possible to avoid shallow water crossings at Goodwin Sands. Marine infrastructure present includes the Kentish Flats, Thanet and London Array, Greater Gabbard and Galloper offshore wind farms and export cables, BritNed and NemoLink interconnectors and the proposed NeuConnet and GridLink Interconnectors. Whilst the offshore wind farms are avoidable, it is unlikely that crossings of cables, could be avoided entirely. As discussed above where these crossings may not be avoided in shallow waters such as Kentish Flats this is considered to be a principle consideration due to potential reduction in water depth.

9.3.7 Whilst (with the exception of the Outer Thames Estuary SPA and cable crossings) most constraints in the marine study area are avoidable when considered in isolation, when considered in combination avoidance may not be possible. Due to the sensitives around Margate and Long Sands SAC in particular, because it is unlikely that the crossing of other existing and proposed infrastructure cannot be avoided within the site, this site divides the marine study areas into two. The site could be avoided to the west however this would require the potential crossing of London Array export cables in shallow water and the crossing of a number of the shipping channels into the Port of London. Liaison with the PLA would be required to confirm the feasibility of a route through this part of the outer Thames Estuary. The site could also be avoided to the east although this would require a route through the Southern North Sea SAC and potentially some interaction with Goodwin Sands MCZ.

9.3.8 In Kent, it is predicted there would be greater socio-economic impacts positioning the cable route east in comparison to the north due to more urban regions being affected, largely due to the eastern shoreline being at a greater distance from Canterbury Substation than the northern shoreline. However, a main constraint for the routeing of the cable north is the settlement Herne Bay which is heavily populated with infrastructure positioned along the shoreline. Positioning of the cables would have to be carefully routed to avoid Herne Bay, the allocation and growth area to the east of Herne Bay and the three local nature reserves identified along the northern shoreline. In addition there is a significant amount of proposed development in the vicinity of Sizewell and the settlements of Leiston and Friston which would need to be considered in combination so as to not tip the balance of development in this area.

9.4 Technical scope and costs

9.4.1 Technical analysis of option SL3 is as follows:

- This option to connect a 120 km circuit between Sizewell Area and Canterbury area allows transfers of energy between Suffolk and Kent, providing a transmission connection to the east of London.
- As this option is only required to provide 2000 MW (2 GW) of capacity between Suffolk and Kent the HVDC option only requires a single HVDC link. The AC option however without the ability to control power flow along the circuit would be required to be of 6380 MW double circuit capacity.
- Because of the capacity of the transmission system to the west of Canterbury, options west of this point would require further transmission reinforcement and would offer less benefit that connections to the east of Canterbury.

9.4.2 As set out in Section 5, we undertook a cost evaluation of the following two technologies for subsea options evaluation.

- 400 kV AC subsea cable.
- 525 kV HVDC subsea cable.

9.4.3 Option SL3 requires the following transmission works to satisfy the requirements of the SQSS.

New Circuit requirements

- AC subsea connections circuit options use Med-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6380 mega volt amperes (MVA) of a distance of 120 km; or
- HVDC connection options use 525 kV 2 GW voltage source links, which would require a convertor station at each end, similar in size to a large warehouse. In this case a 2000 MW (2 GW) connection would require two convertor stations in total, with up to two of the convertors located at the New Walpole Substation;
- Subsea HVDC cables totalling 120 km.

National Grid Substation Works

- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Sizewell;
- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Canterbury.

9.4.4 Table 9.1 below sets out the capital costs for option SL3 considering substation works and each technology option.

Table 9.1 – SL3 capital cost summary

Item	Need	SL3 Capital Cost	
Substation Works	Facilitate generation and connect new circuits	£249.0m	
New Circuits		**AC Subsea Cable (6380 MW)**	**HVDC Subsea (2000 MW)**
New Circuit 120 km	New Circuit across EC5 and SC2	£3,627.7m	£905.2m
Total Capital Cost		**£3,876.7m**	**£1,154.2m**

9.4.5 Table 9.2below sets out the lifetime cost for the new circuit options, the lifetime costs are different for each circuit technology and are included as a differentiator between technologies. These costs are calculated using the methodology described in Appendix D.

Table 9.2 – SL3 lifetime cost summary

Land Based option	SL3 AC Subsea Cable (6380 MW)	SL3 HVDC Subsea (2000 MW)
Capital Cost of New Circuits	£3,627.7m	£905.2m
NPV of cost of losses over 40 years	£224.9m	£157.1m
NPV of operation & maintenance costs over 40 years	£20.4m	£57.5m
Lifetime cost of new circuits	**£3,873m**	**£1,120m**

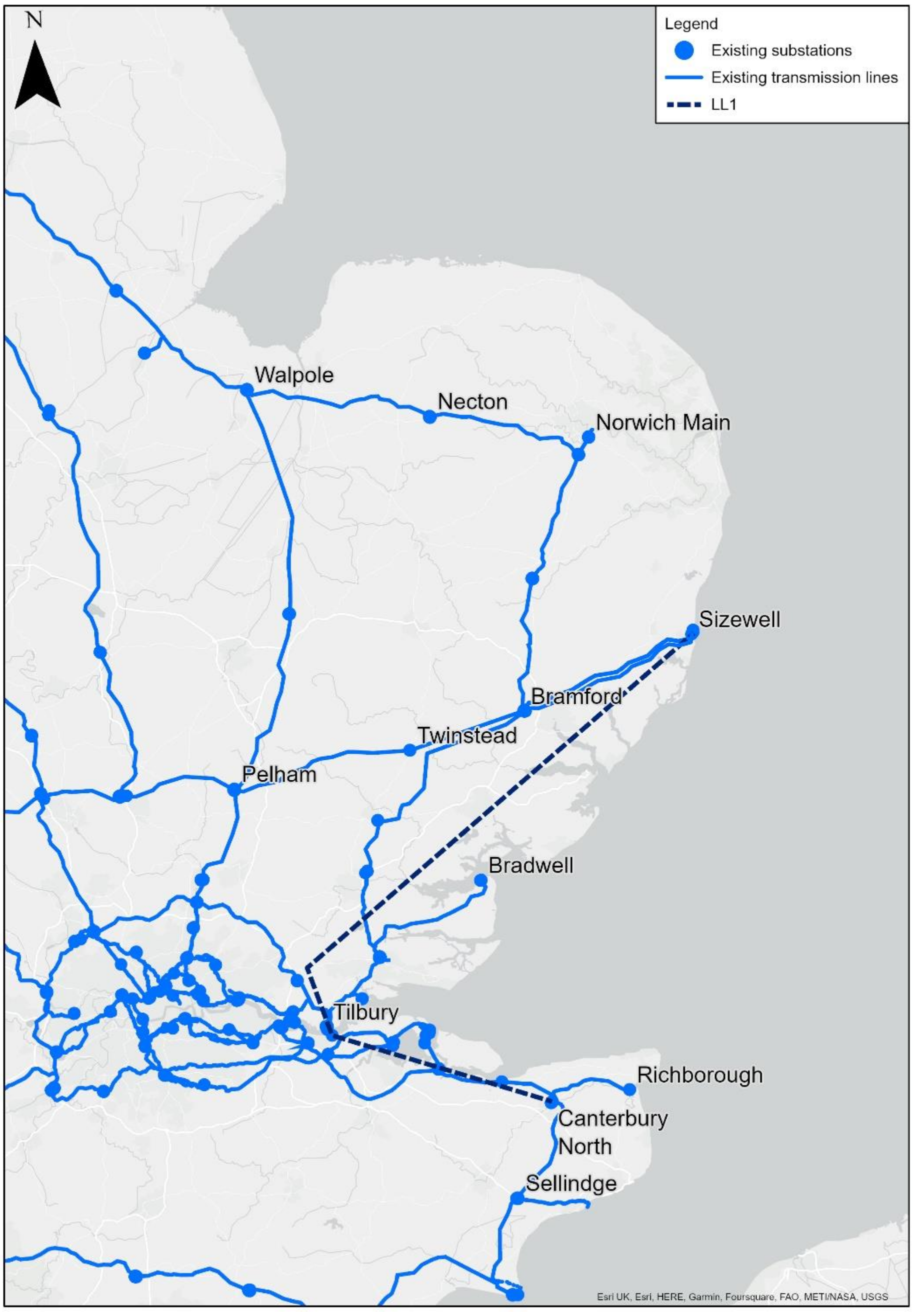
9.4.6 From the environmental and technical appraisal considered, alongside capital and circuit lifetime costs, the preferred option for SL3, is a 2000 MW (2 GW) HVDC link connecting between Sizewell and Canterbury areas, connecting to new substations at each end. In light of this analysis our starting presumption for further development of this option should it be selected, would be for a majority HVDC subsea connection.

10. LL1 – Sizewell Area to Canterbury

10.1 Introduction

10.1.1 Strategic option LL1 involves a new land based transmission connection between a new substation in the geographical vicinity of Sizewell and new substation in the geographical vicinity of Canterbury. a distance of approximately 220 km Shown in Figure 10.1.

Figure 10.1 – Option LL1 Sizewell Area to Canterbury area



10.2 Environmental appraisal

10.2.1 There are a number of sensitive receptors located within the study area that extends across Suffolk, Essex and Kent, which include international and nationally designated sites for nature conservation and heritage. Whilst many of these sites are likely to be avoidable, a large proportion of the eastern side of the study area includes SPAs/SACs and Ramsar sites. Routeing will therefore need to consider bird flight paths. Mitigation for impacts of AC OHL connections on bird populations are available, but no methods exist that eliminate the potential for collision and avoidance behaviour, or displacement of bird populations. Recommended measures for mitigating for bird collision and mortality from AC OHL prioritise eliminating exposure by undergrounding connections (e.g. AC Cable) or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing line-markers and embedding measures into the design (e.g. insulated components, greater air space between lines). The potential for a likely significant effect on these sites will need to be considered in relation to the Habitat Regulations 2017.

10.2.2 The cable route would need to cross the River Thames and its estuary; this is likely to require a crossing via a cable tunnel beneath the river. The Canterbury Substation is located within Flood Zone 2 and 3 and therefore the extension of Canterbury Substation would likely be constructed within a Flood Zone. Similarly, if a new converter station and associated equipment is required at Canterbury Substation, it is likely this would be constructed within a Flood Zone. Due to the extent of development around Canterbury Substation there are limited opportunities to site a converter station in close proximity.

10.2.3 It is likely that designated assets, such as Scheduled Monuments and listed buildings will be avoided. Physical impacts are likely to be limited to non-designated assets and previously unrecorded assets, although these were not assessed as part of this options appraisal. There is however the potential for significant impacts on the setting, with a large number of high value designated assets identified throughout the study area. This could include routeing near areas of previous disturbance, as well as limiting above ground infrastructure in areas of high value receptors. Mitigation will be required, and could include a phased programme of works including geophysical survey, archaeological evaluation trenching, and full archaeological excavation to mitigate physical impacts. The design of any above ground infrastructure required, as well as screening/planting, could potentially mitigate impacts on the setting of designated assets.

10.2.4 Much of the study area comprises constraints to an AC OHL, some of which can be addressed by conventional approaches e.g. routeing/paralleling. Whilst it should be possible with this option to avoid some potential adverse effects on the landscape and visual amenity of the AONBs, it is considered unlikely that all of the impacts could easily be mitigated, and significant residual effects are therefore possible. It is also expected that there will be adverse visual effects to residents along affected settlement edges, scattered properties, and visitors to the areas, through increased ‘wirescape’.

10.3 Socio-economic appraisal

10.3.1 There a number of main settlements within this study area, including Ipswich, Colchester, Felixstowe; Grays/Tilbury; Gravesend, Greater London Urban Area; Basildon, Rochester, Whitstable, Maidstone, Canterbury. It is likely that a new AC OHL would need to be routed in close proximity to settlements. Temporary adverse impacts could arise if the AC OHL is situated within close proximity to settlements during construction associated with noise, air quality and construction traffic. There is the potential for permanent adverse visual effects which are set out in the landscape and visual appraisal above.

10.3.2 Whilst most of this route will be OHL, underground sections will likely be required for within the AONB and across the River Thames Estuary. Temporary adverse impacts could arise if cables are buried in close proximity to settlements during construction associated with noise, air quality and construction traffic.

10.3.3 There is the potential for temporary adverse effects associated with severance should cycle routes and public rights of way need to be temporarily closed during construction. There is the potential for adverse visual effects on users of recreational facilities. Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users if routes are closed/diverted during construction.

10.3.4 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints and converter stations, but this is unlikely to be significant. Other land uses are likely to be avoidable. Standard best practice guidelines should be followed to reinstate agricultural land following construction where possible.

10.3.5 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects on users of roads and railways. Aerodromes located within the study area could potentially be affected. Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice to the public who use the roads should these be temporary closed during construction. Consideration will need to be given to any potential crossings of existing overhead lines. The route would have to pass over gas transmission pipelines, these areas could require additional construction protection methods. Routeing of a new AC OHL would have to take account of the aerodromes located within this study area. Potential requirement for routeing away from exclusion zones and aviation warning lighting on the top of the transmission towers if their location is considered a significant navigational hazard.

10.4 Technical scope and costs

10.4.1 Technical analysis of option LL1 is as follows:

- This option to connect a 220 km land based circuit between Sizewell Area and Canterbury area allows transfers of energy between Suffolk and Kent, providing a transmission connection to the east of London.
- As this option is only required to provide 2000 MW (2 GW) of capacity between Suffolk and Kent the HVDC option only requires a single HVDC link. The AC option however without the ability to control power flow along the circuit would be required to be of 6380 MW double circuit capacity.
- Because of the capacity of the transmission system to the west of Canterbury, options west of this point would require further transmission reinforcement and would offer less benefit that connections to the east of Canterbury.
- This option would need to cross the Thames estuary at a significant crossing distance to the east of London. It is likely that this would need to be done by a tunnel cable crossing adding significant cost.

10.4.2 As set out in Section 5, we undertook a cost evaluation of the following four technologies for onshore options evaluation:

- 400 kV alternating current (AC) overhead Line;
- 400 kV AC underground cable;
- 400 kV AC gas insulated line (GIL);
- 525 kV high voltage direct current (HVDC) underground cable.

10.4.3 Option LL1 requires the following transmission works to satisfy the requirements of the SQSS.

New Circuit requirements

- An onshore AC connection using Med-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6380 mega volt amperes (MVA); or
- An onshore HVDC connection options use 525 kV 2 GW voltage source links, which would require a convertor station at each end (two in total), similar in size to a large warehouse;
- Onshore circuits totalling 220 km.

National Grid Substation Works

- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Sizewell;
- A new 400 kV 8 Bay GIS substation in the geographical vicinity of Canterbury.

10.4.4 Table 10.1 – LL1 capital cost summarybelow sets out the capital costs for option LL1 considering substation works and each technology option.

Table 10.1 – LL1 capital cost summary

Item	Need	LL1 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£249.0m			
New Circuits		**AC OHL (6380 MW)**	**AC Cable (6380 MW)**	**AC GIL (6380 MW)**	**HVDC (2000 MW)**
New Circuit 220 km	New Circuit across EC5 and SC2	£800.8m	£6,689.0m	£6,846.4m	£1,214.2m
Total Capital Cost		**£1,049.8m**	**£6,938.0m**	**£7,095.4m**	**£1463.2m**

10.4.5 Table 10.2 below sets out the lifetime cost for the new circuit options, the lifetime costs are different for each circuit technology and are included as a differentiator between technologies. These costs are calculated using the methodology described in Appendix D

Table 10.2 – LL1 Lifetime cost summary

Land Based option	**LL1 AC OHL (6380 MW)**	**LL1 AC Cable (6380 MW)**	**LL1 AC GIL (6380 MW)**	**LL1 HVDC (2000 MW)**
Capital Cost of New Circuits	£800.8m	£6,689.0m	£6,846.4m	£1,214.2m
NPV of cost of losses over 40 years	£687.5m	£427.6m	£321.3m	£157.1m
NPV of operation & maintenance costs over 40 years	£12.9m	£38.4m	£13.0m	£57.8m
Lifetime cost of new circuits	**£1,501m**	**£7,155m**	**£7,181m**	**£1,429m**

10.4.6 From the environmental and technical appraisal considered, alongside capital and circuit lifetime costs, the preferred option for LL1, is a 2000 MW (2 GW) HVDC link connecting between Sizewell and Canterbury areas, connecting to new substations at each end. For this land based option when considering the capacity required, the overhead line option has the lowest capital cost of £800.8m compared with £1,214m for HVDC. However over the lifetime for the capacity required the AC overhead line circuit lifetime cost £1,501m compared with £1,429m.

10.4.7 This is also noting any AC option currently costed for OHL only (the lowest cost AC solution), would require a cable tunnel and cable to cross the Thames estuary likely to add >£500m of capital cost to the AC OHL option, an additional >£500m to the capital cost of £1,049.8m. It should also be noted that AC Cable & GIL options would require a tunnel for the estuary section, the HVDC option may require a tunnel or alternative options to cross the estuary.

11. Strategic options appraisal conclusions

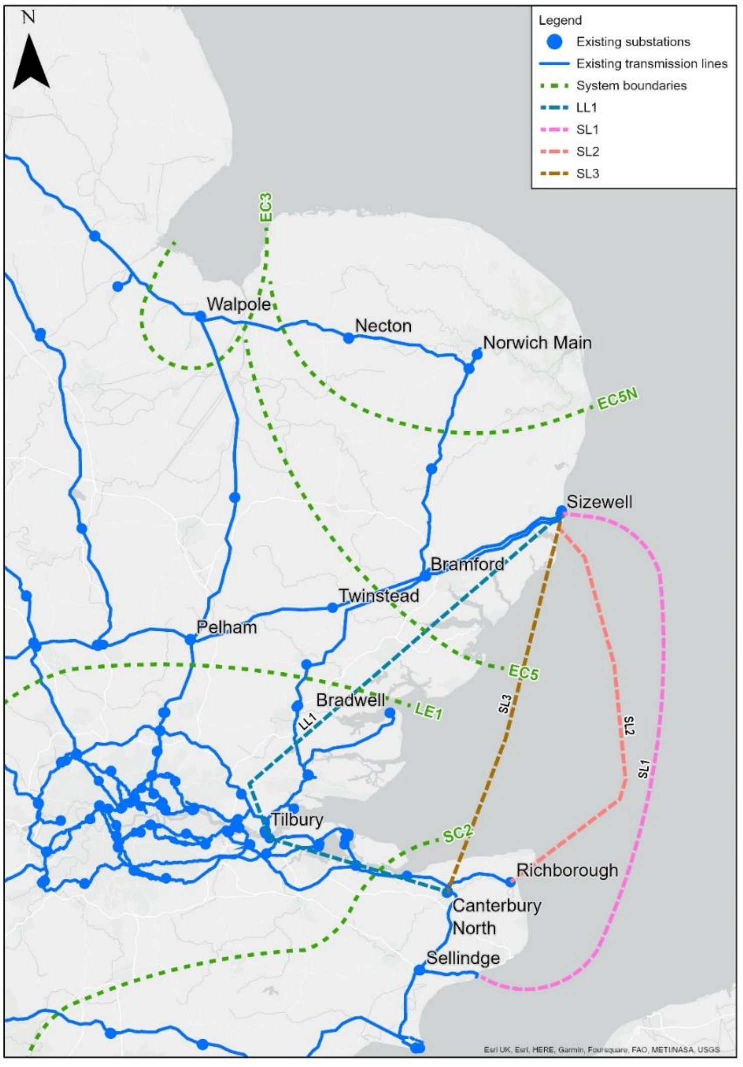
11.1 Introduction

11.1.1 This Strategic Options Report has considered the following options:

- SL1 – Sizewell Area to Sellindge subsea approx. 180 km;
- SL2 – Sizewell Area to Richborough subsea approx. 120 km;
- SL3 – Sizewell Area to Canterbury subsea approx. 120 km;
- LL1 – Sizewell Area to Canterbury onshore approx. 220 km.

11.1.2 These are shown in Figure 11.1 below.

Figure 11.1 – Options considered in this Strategic Options Report



11.1.3 As outlined in further detail in the previous sections, this strategic options assessment considers for each option:

- environmental and socio-economic constraints;
- technology options available and the associated technical considerations; and
- the capital and lifetime costs of each technology option.

11.1.4 The remainder of this section summarises these considerations across the available options.

11.2 Environmental and socio-economic considerations

Suffolk

11.2.1 The coastal areas near Sizewell are part of the Suffolk Coast and Heaths AONB, and the Suffolk Heritage Coast extends along the whole coastline within the Sizewell area. The existing Sizewell substation is within both designations. All options would be likely to impact on these designations. All subsea options would be likely to have very similar impacts, chiefly (in the operational phase) resulting from the necessary converter station. It is also considered unlikely that all of the impacts of onshore option LL1 could easily be mitigated. In all cases there would therefore be limited opportunity to avoid impacts on these designations.

11.2.2 National Policy relating to electricity transmission networks is set out in extant NPS EN-1 and EN-5, including policy for development in nationally designated landscapes. EN-1 confirms that National Parks, the Broads and AONBs have been confirmed by the Government as having the highest status of protection in relation to landscape and scenic beauty. EN-1 makes clear that development consent in these areas can be granted in exceptional circumstances. In such instances, the development should be demonstrated to be in the public interest and consideration of such applications should include an assessment of:

- the need for the development, including in terms of national considerations, and the impact of consenting or not consenting it upon the local economy;
- the cost of, and scope for, developing elsewhere outside the designated area or meeting the need for it in some other way, taking account a consideration of alternatives; and
- any detrimental effect on the environment, the landscape and recreational opportunities, and the extent to which that could be moderated.

11.2.3 In this case, the need case requires connection in the Sizewell area, as demonstrated in Section 3 and elsewhere in this report, and there are therefore no practical alternatives avoiding the AONB altogether. Siting opportunities are available given the location in the area of the current Sizewell nuclear site. These designations are therefore not considered to be differentiators between the options considered in this report.

11.2.4 There are several ecological designations (SPAs, SACs, and SSSIs) in the Sizewell area. However, it is likely that significant effects on the ecology can be avoided or mitigated. These therefore also do not represent differentiators for the options considered.

Kent/South East England

11.2.5 None of the environmental and socio-economic considerations identified appear to represent ‘in-principle’ issues that could not be addressed in accordance with the relevant policies set out in EN-1 and EN-5. Given the similarity in cost and technical terms between SL2 (Richborough) and SL3 (Canterbury) it is particularly relevant to make a comparison of environmental and socio-economic factors to differentiate between the options.

11.2.6 All three landing points for subsea options would be in the vicinity of various ecological designations (SPAs, SACs, SSSIs, MCZs). In the case of Canterbury (SL3), total avoidance is considered unlikely when the designations are considered in combination with other constraints, whereas Richborough would present lesser challenges.

11.2.7 The current Richborough substation is located on the east Kent coast within Richborough Energy Park and is surrounded by similar infrastructure. The siting of a converter station close to the existing substation would be in keeping with the existing infrastructure in this locality. Similarly, Sellindge substation is located adjacent to the M20 and the High Speed 1 (HS1) corridor and the siting of a converter station close to the existing substation would be in keeping with existing infrastructure in this locality. Due to the extent of development around the existing Canterbury substation there are limited opportunities to site a converter station.

11.2.8 Richborough substation is partly within Flood Zone 2, whereas Canterbury and Sellindge substations are in Flood Zone 3.

11.2.9 Taking all environmental and socio-economic factors into account, Richborough (SL2) is preferred over Canterbury (SL3). Sellindge would offer no benefit in environmental or socio-economic terms to justify the greater length of cable, and associated costs, required.

11.2.10 Whilst the environmental and socio-economic appraisal of onshore option LL1 has not identified ‘in-principle’ issues, this option would offer no benefit over the offshore options such as to justify the additional lifetime costs required.

11.3 Technical considerations

11.3.1 The needs case set out in Section 3 requires the following need to be satisfied by a connection between the Sizewell Generation group and the SC2 Boundary in Kent. The following requirement is set out below:

- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

11.3.2 Therefore the provision of 2000 MW between the two areas satisfies this requirement.

11.3.3 As the need case requires the provision of 2000 MW (2 GW) of capacity between Suffolk and Kent the HVDC option only requires a single HVDC link. The AC option does not allow the ability to control power flow along the circuit and would therefore require a 6380 MW double circuit as it is not possible to stop additional energy flowing down the AC route under differing system conditions.

11.3.4 As required by our methodology for offshore options we considered both AC cable and HVDC options. From the cost appraisal in each option it was clear that HVDC over the identified distances provides the best solution.

11.3.5 When considering an onshore alternative we considered all the technologies available, including Overhead Lines, AC Cables, AC Gas Insulated Line (GIL) and land based HVDC. It should be noted as above all AC options required to be of 6380 MW of capacity and 2000 MW for HVDC. Also any AC overhead line solution would require a crossing of the Thames estuary at a substantially wide crossing point, likely requiring the installation of a cable tunnel at significant cost.

11.3.6 With the need to send 2000MW power to Kent during high Sizewell Generation Group output during faults in East Anglia. Whilst also being able to send 2000MW of power to Sizewell Generation Group when high interconnector imports into Kent SC2 and fault conditions occur within SC2. This means that the direction of the 2000MW flow has to be in either direction, HVDC technology provides full power control allowing both these needs to be satisfied by a single 2000MW link.

11.4 Cost considerations

11.4.1 Table 11.1 below provides a comparison of options based on the most economical technology choice for each option (i.e. AC OHL for onshore options; HVDC for Offshore 1).

Table 11.1 – Cost Summary of works required to meet project need

Boundary or Group	Offshore options			Onshore options	
Sizewell and SC2	**SL1 – Sizewell Area to Sellindge**	**SL2 – Sizewell Area to Richborough**	**SL3 – Sizewell Area to Canterbury**	**LL1 – Sizewell Area to Canterbury**	**LL1 – Sizewell Area to Canterbury**
Economic Technology (Capacity)	HVDC 180 km (2000 MW)	HVDC 120 km (2000 MW)	HVDC 120 km (2000 MW)	HVDC 220 km (2000 MW)	AC OHL 220 km (6380 MW)
Capital Cost including non-circuit works	£1,339.6m	£1,154.2m	£1,154.2m	£1,463.2m	£1,049.8m
Circuit 40yr Lifetime NPV Cost	£1,305m	£1,120m	£1,120m	£1,429m	£1,501m

11.4.2 To meet the need case of providing 2,000 MW between Sizewell and SC2, the lowest overall cost combination as indicated in Table 11.1 is:

- SL2 and SL3 – Sizewell Area to Richborough/Canterbury with capital costs of £1,154.2m and lifetime circuit costs of £1,120m.

11.4.3 Onshore option LL1 has overall costs of:

- LL1 Overhead Line – Sizewell to Canterbury with capital cost of £1,049.8m and lifetime circuit cost of £1,501m.
- LL1 HVDC land based – Sizewell to Canterbury with capital cost of £1,463.2m and lifetime circuit cost of £1,429m.

11.4.4 Although the Overhead Line has a slightly lower capital cost of £1,049.8m circa £100m cheaper than the subsea alternatives of SL1 and SL2, the lifetime cost for all HVDC alternatives for this case when only 2000 MW of capacity is required is lower than the AC overhead line lifetime cost. This means that even in the onshore option LL1, HVDC would be preferred.

11.4.5 The cost of LL1 does not also take into account the >£500m of additional cost that would be required for the circuit to make and Tunnel and AC Cable crossing of the Thames Estuary.

11.5 Summary and conclusion

11.5.1 Taking all of the above considerations into account, we propose to take forward option SL2 (HVDC connection between Sizewell Area and Richborough). This is the joint lowest cost overall solution, offering environmental and socio-economic benefits over option SL3 (HVDC between Sizewell Area and Canterbury), the estimated costs of which are similar.

11.5.2 The costlier options SL1 and LL1 do not offer environmental and socio-economic benefits over option SL2 such as to justify the significant additional distance and cost involved.

12. Interaction with other projects

12.1.1 As stated in Section 6, Strategic Options Overview, this report has considered options to address the need case in combination with reinforcements in East Anglia. The need case requires increases in capacity for several system boundaries and generation groups.

12.1.2 Firstly, solutions are required to resolve capacity shortfalls across EC5, EC5N, LE1, Sizewell Generation Group and Essex Generation Group combined. These boundaries are partly resolved by other reinforcements being developed in East Anglia. The Norwich to Tilbury Strategic Options Backcheck and Review report published in June 2023 explains why the current preferred solution in East Anglia is the Norwich to Tilbury project. The Bramford to Twinstead reinforcement, for which development consent is currently being sought from the Secretary of State, also contributes to increasing capacity across EC5.

12.1.3 Secondly, boundary SC2 causes an additional impact due to the need to support energy flow directly into the area for high interconnector export scenarios seen consistently in FES. This means that the Kent area including SC2 requires additional connection capacity to remain compliant with the NETS SQSS.

12.1.4 This report has therefore considered the options to, in combination with Norwich to Tilbury, resolve the need for power transfer between East Anglia and the South East of England, resolving capacity shortfalls across SC2, as well as EC5, LE1 and the Sizewell Generation Group.

12.1.5 Notwithstanding the interactivity of the need cases for these reinforcements, given that the options considered in the Norwich to Tilbury Strategic Options Backcheck and Review all cross the same system boundaries and connect substations in the north of Norfolk with Tilbury, the conclusions made by this report are not sensitive to any future changes to the options selected in East Anglia. As demonstrated by the needs case, there is a strong driver for transfer of power from the Sizewell area to the Kent SC2 boundary area of England.

13. Conclusion and next steps

13.1 Conclusions

13.1.1 As explained in Section 2, we have a key role providing a transmission system which benefits all consumers in England and Wales. Where new network infrastructure is needed, we must work within the regulatory, legislative and policy framework that is set by government on behalf of consumers and society in developing proposals. That means considering the various benefits and impacts that our potential works could have, including environmental, socio-economic, technical and cost factors.

13.1.2 This report has considered options to meet the Need Case set out in Section 4. A requirement has been identified for two sets of transmission circuits that contribute to National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) compliance.

13.1.3 We have considered the information which is available to us at this stage of the process. We have outlined in this report how we have gathered data and how we have evaluated it for each option. In addition to this, we have also considered our duties under the Electricity Act 1989 to develop efficient, co-ordinated and economical solutions, our duty to have regard to the environment in Schedule 9 of the 1989 Act, and the policy, advice and guidance provided by Government through the adopted and emerging National Policy Statements EN-1, EN-3 and EN-5.

13.1.4 Taking all of this into account, to meet the need to increase capacity across boundaries EC5N, EC5, LE1, SC2 and provide the required capacity for the Sizewell and Essex Coast Generation Groups, we propose at the current stage to take forward a preference of option **SL2 HVDC connection between Sizewell Area and Richborough**. This option is the joint lowest cost overall solution, offering environmental and socio-economic benefits over option SL3 (HVDC between Sizewell Area and Canterbury), the estimated costs of which are similar. The costlier options SL1 and LL1 do not offer environmental and socio-economic benefits over option SL2 such as to justify the significant additional distance and cost involved.

13.1.5 This option would be taken forward in combination with the Norwich to Tilbury reinforcement in East Anglia, or a variant of equivalent capability. We will continue to review our work including in light of changes in circumstances and we will have regard to consultation responses.

13.1.6 This combination of options (SL2 alongside Norwich to Tilbury) resolves the needs case set out below:

- Provision of 8,084 MW of capacity across East Anglia EC5 Boundary and 3,492 MW of capacity across EC5N Boundary.
- Provision of 7,576 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,580 MW of connection capacity for the Essex Coast Generation Group
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

13.2 Next steps

13.2.1 The Proposed Project has already been subject to non-statutory consultation, and this report confirms that it remains the optimal option to progress to meet the need case outlined. The Proposed Project will now be taken forward to the next stage of development, including a statutory consultation under Part 5 of the Planning Act 2008 to seek feedback from consultees, landowners and the local community to help shape the further development of the Proposed Project.

Appendix A Summary of National Grid Electricity Transmission Legal Obligations

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1.1 Electricity Transmission Licence

1.1.1 The Electricity Act 1989 (the ‘Electricity Act’) defines transmission of electricity within GB and its offshore waters, as a prohibited activity, which cannot be carried out without permission by a transmission licence granted under Section 6(1)(b) of the Electricity Act (a ‘Transmission Licence’).

1.1.2 National Grid Electricity Transmission (‘National Grid’) has been granted a Transmission Licence that permits transmission owner activities in respect of the electricity transmission system National Grid owns, develops and maintains in England and Wales.

1.1.3 Each Transmission Licence includes conditions which define the scope of the permission granted to carry out a prohibited activity in terms of duties, obligations, restrictions and rights. The generic conditions that apply to any holder of a Transmission Owner licence type are set out in Sections A, B and D of the Standard Conditions of the Transmission Licence. Conditions that only apply to a specific licensee are set out as Special Conditions of that Transmission Licence.

1.1.4 National Grid is therefore bound by the legal obligations primarily set out in the Electricity Act and its Transmission Licence. The following list provides a summary overview of requirements that are considered when developing proposals to construct new transmission system infrastructure.

1.2 Electricity Act Duties

1.2.1 In accordance with Section 9 of the Electricity Act, National Grid is required to develop and maintain an efficient, coordinated and economical system of electricity transmission.

1.2.2 Schedule 9 of the Electricity Act requires National Grid, when formulating proposals for new lines and other works, to:

"…have regard to the desirability of preserving natural beauty, of conserving flora, fauna, and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and to do what [it] reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects".

1.2.3 National Grid's Stakeholder, Community and Amenity Policy (‘the Policy‘) sets out how the company will meet this Schedule 9 duty. The commitments within the Policy include:

- only seeking to build new lines and substations where the existing transmission infrastructure cannot be upgraded technically or economically to meet transmission security standards;
- where new infrastructure is required, seeking to avoid areas that are nationally or internationally designated for their landscape, wildlife or cultural significance, and
- minimising the effects of new infrastructure on other sites valued for their amenity.

1.2.4 The Policy also refers to the application of best practice methods to assess the environmental impacts of proposals and identify appropriate mitigation and/or offsetting measures. Effective consultation with stakeholders and the public is also promoted by the Policy.

1.3 National Grid's Transmission Licence Requirements

1.3.1 Condition B12: System Operator – Transmission Owner Code

All Transmission Licensees are required to have the System Operator Transmission Owner Code ('STC') in place that defines the arrangements within the transmission sector and sets out how the transmission system operator can access and use transmission services provided by transmission owners.

The STC structure aligns with key activities within the transmission sector including:

- Planning Co-ordination (of transmission system development works and construction);
- Provision of transmission services within different operational timescales, and
- Payments from transmission system operator to providers of transmission services (after service has been delivered).

1.3.2 Condition B16: Electricity Network Innovation Strategy

All Transmission Licensees are required to have a joined-up approach to innovation and develop an Electricity Network Innovation Strategy that is reviewed every two years.

1.3.3 Condition D2: Obligation to provide transmission services

Each transmission owner is required to provide transmission services to the transmission system operator as defined in the STC. Transmission services provided to the transmission system operator include:

- enabling use to be made of existing transmission owner assets, and
- responding to requests for the construction of additional transmission system capacity (including system extension, disconnections and/or reinforcement).

1.3.4 Condition D3: Transmission system security standard and quality of service

Transmission owners are required to at all times plan, develop the transmission system in accordance with the National Electricity Transmission System Security and Quality of Supply Standard ('NETS SQSS').

A transmission owner with supporting evidence, may ask the Authority to grant derogation from the requirements set out in the NETS SQSS. Any decision in respect of NETS SQSS derogations are subject to the Authority's consideration of all relevant factors.

1.3.5 Condition D17: Whole Electricity System Obligations

Transmission owners are required to coordinate and cooperate with Transmission Licensees and electricity distributors in order to build common understanding of where actions taken by one could have cross-network impacts. A transmission owner should implement actions or processes that are identified that:

- will not have a negative impact on its network, and

- are in the interest of the efficient and economical operation of the total system.

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Appendix B
Requirement for Development Consent Order

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1.1 Electricity Network Infrastructure Developments

1.1.1 Developing the electricity transmission system in England and Wales subject to the type and scale of the project, may require one or more statutory consents which may include:

- planning permission under the Town and Country Planning Act 1990;
- a marine licence under the Marine and Coastal Access Act 2009;
- a Development Consent Order ("DCO") under the Planning Act 2008, and/or
- a variety of consents under related legislation, such as the Electricity Act 1989.

1.1.2 The Planning Act 2008 defines developments of new electricity overhead lines of 132 kV and above as Nationally Significant Infrastructure Projects ('NSIPs') requiring a DCO. Such an order may also incorporate Consent for other types of work that is associated with new overhead line infrastructure development, may be incorporated as part of a DCO that is granted.

1.1.3 Six National Policy Statements ("NPS") for energy infrastructure were designated by the Secretary of State for Energy and Climate Change in July 2011. The relevant NPSs for electricity transmission infrastructure developments are the Overarching National Policy Statement for Energy (EN-1) and the National Policy Statement for Electricity Networks Infrastructure (EN-5), which is read in conjunction with EN-1. In September 2021, Government consulted[10] on proposed updates to the NPS suite including EN-1 and EN-5. The proposed updates include clear linkages of EN-1 with policy objectives in respect of net-zero[11]. Further drafts of NPS EN-1, EN-3 and EN-5 were issued in March 2023.

1.1.4 Section 104(3) of the Planning Act 2008 states that the decision maker must determine an application for a DCO in accordance with any relevant NPS, except in certain specified circumstances (such as where the adverse impact of the proposed development would outweigh its benefits). The energy NPSs therefore provide the primary policy basis for decisions on DCO applications for electricity transmission projects. The NPSs may also be a material consideration for decisions on other types of development consent in England and Wales (including offshore wind generation projects) and for planning applications under the Town and Country Planning Act 1990.

1.2 Demonstrating the Need for a Project

1.2.1 Part 3 of EN-1 sets out Government policy on the need for new nationally significant energy infrastructure projects. Paragraph 3.1 confirms that the UK needs all of the types of energy infrastructure covered by the NPS to achieve energy security and to dramatically reduce greenhouse gas emissions. It states that "substantial weight" should be given to the contribution which projects would make towards satisfying each need.

[10] BEIS Consultation, Planning for new infrastructure: review of energy National Policy Statements, September 2021 https://www.gov.uk/government/consultations/planning-for-new-energy-infrastructure-review-of-energy-national-policy-statements

[11] Energy White Paper: Powering our net zero future, December 2020 https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

1.2.2 Description of the need for:

- new electricity transmission infrastructure is set out in EN-1 and EN-5
- new offshore/onshore wind generation is set out in EN-1 and EN-3, and
- new nuclear generation is set out in EN-1 and EN-6.

1.2.3 The need for new transmission infrastructure for this project is described in section 3 of this Report.

1.3 Assessment Principles Applied by Decision Maker

1.3.1 Part 4 of EN-1 sets out the general policies that are applied in determining DCO applications relating to new energy infrastructure. Paragraphs 2.3-2.5 of EN-5 set out the general assessment principles in the specific context of electricity networks infrastructure.

1.3.2 Principles of particular importance for transmission infrastructure projects include:

1.3.3 Presumption in Favour of Development

- Section 4.1 of EN-1 requires the Infrastructure Planning Commission ('IPC') to start with a presumption in favour of granting consent for energy NSIPs. This presumption applies unless any more specific and relevant policies set out in the relevant NPS clearly indicate that consent should be refused. The presumption is also subject to the exceptions set out in Section 104(2) of the Planning Act 2008.
- In assessing any application, the IPC should take account of potential:
  - benefits (e.g. the contribution to meeting the need for energy infrastructure, job creation and long term wider benefits), and
  - adverse impacts (e.g. long term and cumulative impacts but taking into account proposed mitigation measures.

1.3.4 Consideration of Alternatives

- Section 4.4 of EN-1 states that, from a planning policy perspective alone, there is no general requirement to consider alternatives or to establish whether the proposed project represents the best option. However, in relation to electricity transmission projects, paragraph 2.8.4 of EN-5 states that, "*wherever the nature or proposed route of an overhead line proposal makes it likely that its visual impact will be particularly significant, the applicant should have given appropriate consideration to the potential costs and benefits of other feasible means of connection or reinforcement, including underground and subsea cables where appropriate*."
- Section 4.4 of EN-1 also makes clear that there will be circumstances where an applicant is specifically required to include information in their application about the main alternatives that were considered. These circumstances may include requirements under the Habitats Directive and the Birds Directive[12]

1.3.5 Adverse Impacts and Potential Benefits

[12] Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora; Council Directive 2009/147/EC on the conservation of wild birds.

- Part 5 of EN-1 covers the impacts that are common across all energy NSIPs and sections 2.6-2.9 of EN-5 consider impact in the specific context of electricity networks infrastructure.
- Those impacts identified in EN-1 include air quality and emissions, biodiversity and geological conservation, civil and military aviation and defence interests, coastal change (to the extent in or proximate to a coastal area), dust, odour, artificial light, smoke, steam and insect infestation, flood risk, historic environment, landscape and visual, land use, noise and vibration, socio-economic effects, traffic and transport, waste management and water quality and resources. The extent to which these impacts are relevant to a particular stage of a project, or are a relevant differentiator at a particular stage of the options appraisal process, will vary. In particular, some of these impacts are scoped out of this stage of the options appraisal process for this project. EN-5 considers specific potential impacts of electricity networks on biodiversity and geological conservation, landscape and visual, noise and vibration, and electric and magnetic fields.
- Potential impacts of particular importance for electricity transmission infrastructure projects include:

1.3.6 Good Design

- Section 4.5 of EN-1 stresses the importance of 'good design' for energy infrastructure, explaining that this goes beyond aesthetic considerations as fitness for purpose and sustainability are equally important. It is acknowledged in EN-1 that the nature of much energy infrastructure development will often limit the extent to which it can contribute to the enhancement of the quality of the area. Section 2.5 of EN-5 identifies a particular need for the applicant to demonstrate the principles of good design were applied in the proposed approach to mitigating the potential adverse impacts which can be associated with overhead lines.

1.3.7 Climate Change

- Section 4.8 of EN-1 explains how the effects of climate change should be taken into account and section 2.4 of EN-5 expands on this in the specific context of electricity/networks infrastructure. DCO applications are required to set out the vulnerabilities/resilience of the proposals to flooding, effects of wind on overhead lines, higher average temperatures leading to increased transmission losses and earth movement or subsidence caused by flooding or drought (for underground cables).

1.3.8 Networks DCO Applications Submitted in Isolation

- Section 2.3 of EN-5 confirms that it can be appropriate for DCO applications for new transmission infrastructure to be submitted separately from applications for the generation that this infrastructure will serve. EN-5 explains that the need for the transmission project can be assessed on the basis of both contracted and reasonably anticipated generation.

1.3.9 Electricity Act Duties

- Paragraph 2.3.5 of EN-5 recognises developers’ duties pursuant to section 9 of the Electricity Act to bring forward efficient and economical proposals in terms of network design, taking into account current and reasonably anticipated future generation demand, and its duty to facilitate competition and so provide a connection whenever and wherever one is required.

1.3.10 Adverse Impacts and Potential Benefits

- Part 5 of EN-1 covers the impacts that are common across all energy NSIPs and sections 2.6-2.9 of EN-5 consider impact in the specific context of electricity networks infrastructure.
- Those impacts identified in EN-1 include air quality and emissions, biodiversity and geological conservation, civil and military aviation and defence interests, coastal change (to the extent in or proximate to a coastal area), dust, odour, artificial light, smoke, steam and insect infestation, flood risk, historic environment, landscape and visual, land use, noise and vibration, socio-economic effects, traffic and transport, waste management and water quality and resources. The extent to which these impacts are relevant to a particular stage of a project, or are a relevant differentiator at a particular stage of the options appraisal process, will vary. In particular, some of these impacts are scoped out of this stage of the options appraisal process for this project. EN-5 considers specific potential impacts of electricity networks on biodiversity and geological conservation, landscape and visual, noise and vibration, and electric and magnetic fields.
- Potential impacts of particular importance for electricity transmission infrastructure projects include:
  - Landscape and Visual

    Paragraph 2.8.2 of EN-5 states that the Government does not believe that development of overhead lines is generally incompatible in principle with the developer statutory duty under section 9 of the Electricity Act 1989 to have regard to amenity and to mitigate impacts. However, EN-5 recognises that in practice overhead lines can give rise to adverse landscape and visual impacts, dependent upon their scale, siting, degree of screening and the nature of the landscape and local environment through which they are routed.

    In relation to alternative technologies for electricity transmission projects, paragraph 2.8.9 of EN-5 states that,

    "each project should be assessed individually on the basis of its specific circumstances and taking account of the fact that Government has not laid down any general rule about when an overhead line should be considered unacceptable. The IPC should, however, only refuse consent for overhead line proposals in favour of an underground or subsea line if it is satisfied that the benefits from the non-overhead line alternative will clearly outweigh any extra economic, social and environmental impacts and the technical difficulties are surmountable."

    Paragraph 2.8.7 of EN-5 endorses the Holford Rules which are a set of "common sense" guidelines for routeing new overhead lines.

Appendix C Technology Overview

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1.1 Introduction

1.1.1 This section provides an overview of the technologies available when the strategic options described in this Report were identified. It provides a high-level description of the relevant features of each technology. The costs for each technology are presented in Appendix D.

1.1.2 The majority of electricity systems throughout the world are AC systems. Consumers have their electricity supplied at different voltages depending upon the amount of power they consume e.g. 230V for domestic customers and 11 kV for large factories and hospitals. The voltage level is relatively easy to change when using AC electricity, which means a more economical electricity network can be developed for customer requirement. This has meant that the electrification of whole countries could be and was delivered quickly and efficiently using AC technology.

1.1.3 DC electricity did not develop as the means of transmitting large amounts of power from generating stations to customers because DC is difficult to transform to a higher voltage and bulk transmission by low voltage DC is only effective for transporting power over short distances. However, DC is appropriate in certain applications such as the extension of an existing AC system or when providing a connection to the transmission system.

1.1.4 In terms of voltage, the transmission system in England and Wales operates at both 275 kV and 400 kV. The majority of National Grid's transmission system is now constructed and operated at 400 kV, which facilitates higher power transfers and lower transmission losses.

1.1.5 There are a number of different technologies that can be used to provide transmission connections. These technologies have different features which affect how, when and where they can be used. The main technology options for electricity transmission are:

- Overhead lines
- Underground cables
- Gas Insulated Lines ("GIL"), and
- High Voltage Direct Current (HVDC).

1.1.6 This appendix provides generic information about each of these four technologies. Further information, including a more detailed technical review is available in a series of factsheets that can be found at the project website referenced at the beginning of this Report.

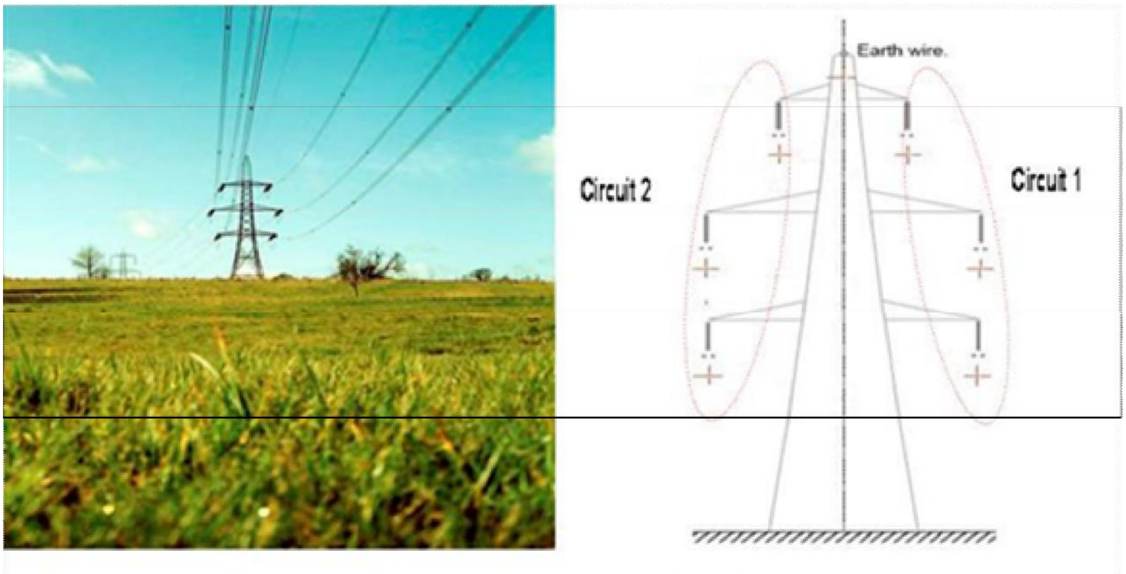
1.2 Overhead lines

1.2.1 Overhead lines form the majority of the existing transmission system circuits in Great Britain and in transmission systems across the world. As such there is established understanding of their construction and use.

1.2.2 Overhead lines are made up of three main component parts which are; conductors (used to transport the power), pylons (used to support the conductors) and insulators (used to safely connect the conductors to pylons).

1.2.3 Figure C.1 shows a typical pylon used to support two 275 kV or 400 kV overhead line circuits. This type of pylon has six arms (three either side), each carrying a set (or bundle) of conductors.

Figure C.1: Example of a 400 kV Double-circuit Tower



1.2.4 The number of conductors supported by each arm depends on the amount of power to be transmitted and will be either two, three or four conductors per arm. Technology developments have increased the capacity that can be carried by a single conductor and therefore, new overhead lines tend to have two or three conductors per arm.

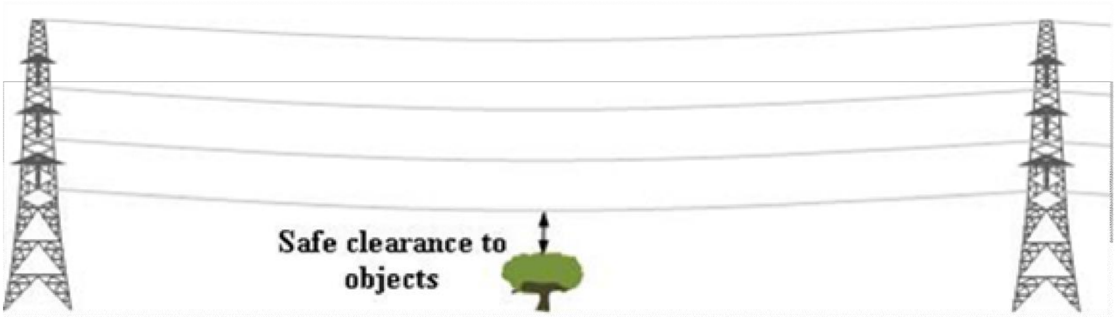
1.2.5 With the conclusion of the Royal Institute of British Architects (RIBA) pylon design competition[13] and other recent work with manufacturers to develop alternative pylon designs, National Grid is now able to consider a broader range of pylon types, including steel lattice and monopole designs. The height and width is different for each pylon type, which may help National Grid to manage the impact on landscape and visual amenity better. Figure C.2, below, shows an image on the monopole design called the T-pylon that was developed by National Grid.

[13] Pylon Design an RIBA competition, https://www.architecture.com/awards-and-competitions-landing-page/competitions-landing-page/pylon

Figure C.2: The T-pylon

1.2.6 Pylons are designed with sufficient height to ensure that the clearances between each conductor and between the lowest conductor and the ground, buildings or structures are adequate to prevent electricity jumping across. The minimum clearance between the lowest conductor and the ground is normally at the mid-point between pylons. There must be sufficient clearance between objects and the lowest point of the conductor as shown in Figure C.3.

Figure C.3: Safe height between lowest point of conductor and other obstacle ("Safe Clearance")



1.2.7 The distance between adjacent pylons is termed the 'span length'. The span length is governed by a number of factors, the principal ones being pylon height, number and size of conductors (i.e. weight), ground contours and changes in route direction. A balance must therefore be struck between the size and physical presence of each tower versus the number of towers; this is a decision based on both visual and economic aspects. The typical 'standard' span length used by National Grid is approximately 360m.

1.2.8 Lower voltages need less clearance and therefore the pylons needed to support 132 kV lines are not as high as traditional 400 kV and 275 kV pylons. However, lower voltage circuits are unable to transport the same levels of power as higher voltage circuits.

1.2.9 National Grid has established operational processes and procedures for the design, construction, operation and maintenance of overhead lines. Circuits must be taken out of service from time to time for repair and maintenance. However, shorter emergency restoration times are achievable on overhead lines as compared, for example, to underground cables. This provides additional operational flexibility if circuits need to be rapidly returned to service to maintain a secure supply of electricity when, for example, another transmission circuit is taken out of service unexpectedly.

1.2.10 In addition, emergency pylons can be erected in relatively short timescales to bypass damaged sections and restore supplies. Overhead line maintenance and repair therefore does not significantly reduce security of supply risks to end consumers.

1.2.11 Each of the three main components that make up an overhead line has a different design life, which are:

- Between 40 and 50 years for overhead line conductors
- 80 years for pylons
- Between 20 and 40 years for insulators.

1.2.12 National Grid expects an initial design life of around 40 years, based on the specified design life of the component parts. However, pylons can be easily refurbished and so substantial pylon replacement works are not normally required at the end of the 40 year design life.

1.3 Underground Cables

1.3.1 Underground cables at 275 kV and 400 kV make up approximately 10% of the existing transmission system in England and Wales, which is typical of the proportion of underground to overhead equipment in transmission systems worldwide. Most of the underground cable is installed in urban areas where achieving an overhead route is not feasible. Examples of other situations where underground cables have been installed, in preference to overhead lines, include crossing rivers, passing close to or through parts of nationally designated landscape areas and preserving important views.

1.3.2 Underground cable systems are made up of two main components – the cable and connectors. Connectors can be cable joints, which connect a cable to another cable, or overhead line connectors in a substation.

1.3.3 Cables consist of an electrical conductor in the centre, which is usually copper or aluminium, surrounded by insulating material and sheaths of protective metal and plastic. The insulating material ensures that although the conductor is operating at a high voltage, the outside of the cable is at zero volts (and therefore safe). Figure C.4 shows a cross section of a transmission cable and a joint that is used to connect two underground cables.

Figure C.4: Cable Cross-Section and Joint

1.3.4 Underground cables can be connected to above-ground electrical equipment at a substation, enclosed within a fenced compound. The connection point is referred to as a cable sealing end. Figure C.5 shows two examples of cable sealing end compounds.

Figure C.5: Cable Sealing End Compounds

1.3.5 An electrical characteristic of a cable system is capacitance between the conductor and earth. Capacitance causes a continuous ‘charging current’ to flow, the magnitude of which is dependent on the length of the cable circuit (the longer the cable, the greater the charging current) and the operating voltage (the higher the voltage the greater the current). Charging currents have the effect of reducing the power transfer through the cable.

1.3.6 High cable capacitance also has the effect of increasing the voltage along the length of the circuit, reaching a peak at the remote end of the cable.

1.3.7 National Grid can reduce cable capacitance problems by connecting reactive compensation equipment to the cable, either at the ends of the cable, or, in the case of longer cables, at regular intervals along the route. Specific operational arrangements and switching facilities at points along the cable circuit may also be needed to manage charging currents.

1.3.8 Identifying faults in underground cable circuits often requires multiple excavations to locate the fault and some repairs require removal and installation of new cables, which can take a number of weeks to complete.

1.3.9 High voltage underground cables must be regularly taken out of service for maintenance and inspection and, should any faults be found and depending on whether cable excavation is required, emergency restoration for security of supply reasons typically takes a lot longer than for overhead lines (days rather than hours).

1.3.10 The installation of underground cables requires significant civil engineering works. These make the construction times for cables longer than overhead lines.

1.3.11 The construction swathe required for two AC circuits comprising two cables per phase will be between 35-50 m wide.

1.3.12 Each of the two main components that make up an underground cable system has a design life of between 40 and 50 years.

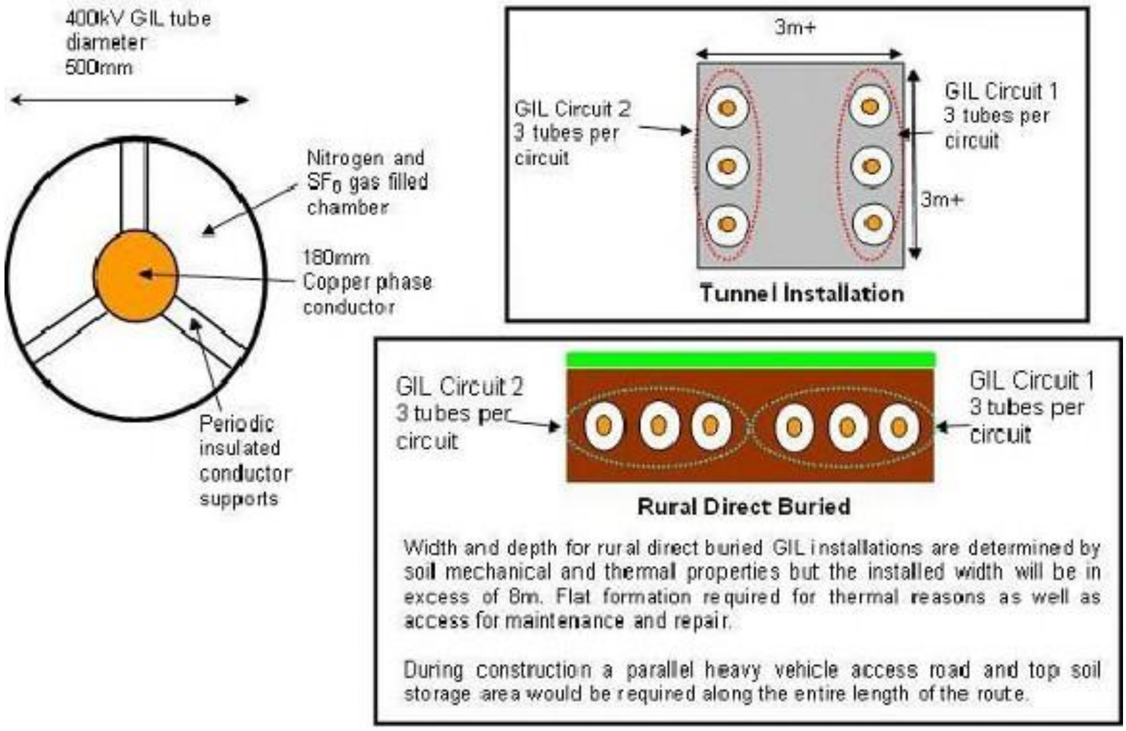
1.3.13 Asset replacement is generally expected at the end of design life. However, National Grid's asset replacement decisions (that are made at the end of design life) will also take account of actual asset condition and may lead to actual life being longer than the design life.

1.4 Gas Insulated Lines ("GIL")

1.4.1 GIL is an alternative to underground cable for high voltage transmission. GIL has been developed from the well-established technology of gas-insulated switchgear, which has been installed on the transmission system since the 1960s.

1.4.2 GIL uses a mixture of nitrogen and sulphur hexafluoride (SF6) gas to provide the electrical insulation. GIL is constructed from welded or flanged metal tubes with an aluminium conductor in the centre. Three tubes are required per circuit, one tube for each phase. Six tubes are therefore required for two circuits, as illustrated in Figure C.6 below.

Figure C.6: Key Components of GIL



1.4.3 GIL tubes are brought to site in 10 – 20 m lengths and they are joined in situ. It is important that no impurities enter the tubes during construction as impurities can cause the gas insulation to fail. GIL installation methods are therefore more onerous than those used in, for example, natural gas pipeline installations.

1.4.4 A major advantage of GIL compared to underground cable is that it does not require reactive compensation.

1.4.5 The installation widths over the land can also be narrower than cable installations, especially where more than one cable per phase is required.

1.4.6 GIL can have a reliability advantage over cable in that it can be re-energised immediately after a fault (similar to overhead lines) whereas a cable requires investigations prior to re-energisation. If the fault was a transient fault it will remain energised and if the fault was permanent the circuit will automatically and safely de-energise again.

1.4.7 There are environmental concerns with GIL as the SF_6[14] gas used in the insulating gas mixture is a potent ‘greenhouse gas’. Since SF6 is an essential part of the gas mixture GIL installations are designed to ensure that the risk of gas leakage is minimised.

1.4.8 There are a number of ways in which the risk of gas leakage from GIL can be managed, which include:

- use of high-integrity welded joints to connect sections of tube;
- designing the GIL tube to withstand an internal fault; and

[14] SF_6 is a greenhouse gas with a global warming potential, according to the Intergovernmental Panel on Climate Change, Working Group 1 (Climate Change 2007, Chapter 2.10.2), of 22,800 times that of CO2. www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

- splitting each GIL tube into a number of smaller, discrete gas zones that can be independently monitored and controlled.

1.4.9 At decommissioning the SF_6 can be separated out from the gas mixture and either recycled or disposed of without any environmental damage.

1.4.10 GIL is a relatively new technology and therefore has limited historical data, meaning that its operational performance has not been empirically proven. National Grid has two GIL installations on the transmission system which are 545 m and 150 m long[15]. These are both in electricity substations; one is above ground and the other is in a trough. The longest directly buried transmission voltage GIL in the world is approximately one kilometre long and was recently installed on the German transmission system around Frankfurt Airport.

1.4.11 In the absence of proven design life information, and to promote consistency with assessment of other technology options, National Grid assesses GIL over a design life of up to 40 years.

1.5 High Voltage Direct Current ("HVDC")

1.5.1 HVDC technology can provide efficient solutions for the bulk transmission of electricity between AC electricity systems (or between points on an electricity system).

1.5.2 There are circumstances where HVDC has advantages over AC, generally where transmission takes place over very long distances or between different, electrically-separate systems, such as between Great Britain and countries in Europe such as France, Belgium, The Netherlands, Ireland etc.…

1.5.3 HVDC links may also be used to connect a generating station that is distant from the rest of the electricity system. For example, very remote hydro-electric schemes in China are connected by HVDC technology with overhead lines.

1.5.4 Proposed offshore wind farms to be located over 60 km from the coast of Great Britain are likely to be connected using HVDC technology as an alternative to an AC subsea cable. This is because AC subsea cables over 60 km long have a number of technical limitations, such as high charging currents and the need for mid-point compensation equipment.

1.5.5 The connection point between AC and DC electrical systems has equipment that can convert AC to DC (and vice versa), known as a converter. The DC electricity is transmitted at high voltage between converter stations. Convertor stations can use two types of technology. "Classic" or Current Source Convertors (CSC) were the first type of HVDC technology developed and this design was used for National Grid's Western Link. Voltage Source Convertors (VSC) are a newer design and offer advantages over the previous CSC convertors, as they can better support weaker systems and offer more flexibility in the way they operate, including direction of power flow.

[15] The distances are based on initial manufacturer estimates of tunnel and buried GIL dimensions which would be subject to full technical appraisal by National Grid and manufacturers to achieve required ratings which may increase the separation required. It should be noted that the diagram does not show the swathe of land required during construction. Any GIL tunnel installations would have to meet the detailed design requirements of National Grid for such installations.

Figure C.7: VSC convertor Station

1.5.6 HVDC can offer advantages over AC underground cable, such as:

- a minimum of two cables per circuit is required for HVDC whereas a minimum of three cables per circuit is required for AC.
- reactive compensation mid-route is not required for HVDC.
- cables with smaller cross sectional areas can be used (compared to equivalent AC system rating).
- This allows HVDC cables to be more easily installed for subsea applications than AC cables for a given capacity.

1.5.7 HVDC cables are generally based upon two technology types Mass Impregnated and Extruded technologies. VSC technology may utilise either technology type, whereas CSC technology tends to be limited to Mass Impregnated cables due to the way poles are reversed for change of power flow direction.

Figure C.8: HVDC Cable Laying Barge at transition between shore and sea cables

1.5.8 HVDC systems have a design life of about 40 years. This design life period is on the basis that large parts of the converter stations (valves and control systems) would be replaced after 20 years.

Appendix D Economic Appraisal

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1.1 Introduction

1.1.1 As part of the economic appraisal of Strategic Options, National Grid makes comparative assessments of the lifetime costs associated with each technology option that is considered to be feasible.

1.1.2 This section provides an overview of the methods that National Grid uses to estimate lifetime costs as part the economic appraisal of a Strategic Option. It also provides a summary of generic capital cost information for transmission system circuits for each technology option included in Appendix C and an overview of the method that National Grid uses to assess the Net Present Value ("NPV") of costs that are expected to be incurred during the lifetime of new transmission assets.

1.1.3 The IET, PB/CCI Report[16] presents cost information in size of transmission circuit capacity categories for each circuit design that was considered as part of the independent study. To aid comparison between the cost data presented in the IET PB/CCI Report and that used by National Grid for appraisal of Strategic Options, this appendix includes cost estimates using National Grid cost data for circuit designs that are equivalent to those considered as part of the independent study. Examples in this Appendix are presented using the category size labels of "Lo", "Med" and "Hi" used in the IET PB/CCI Report.

1.2 Lifetime Costs for Transmission

1.2.1 For each technology option appraised within a Strategic Option, National Grid estimates total lifetime costs for the new transmission assets. The total lifetime cost estimate consists of the sum of the estimates of the:

- initial capital cost of developing, procuring, installing and commissioning the new transmission assets, and
- net present value ("NPV") of costs that are expected to be incurred during the lifetime of these new transmission assets

1.3 Capital Cost Estimates

1.3.1 At the initial appraisal stage, National Grid prepares indicative estimates of the capital costs. These indicative estimates are based on the high-level scope of works defined for each Strategic Option in respect of each technology option that is considered to be feasible. As these estimates are prepared before detailed design work has been carried out, National Grid takes account of equivalent assumptions for each option. Final project costs for any solution taken forward following detailed design and risk mitigation will be in excess of any high-level appraisal cost. However, all options would incur these increases in the development of a detailed solution.

1.3.2 This section considers the capital costs in two parts, firstly the AC technology costs are discussed, followed by HVDC technologies. Each of these technologies is described in Appendix C in more detail.

[16] "Electricity Transmission Costing Study – An Independent Report Endorsed by the Institution of Engineering & Technology" by Parsons Brinckerhoff in association with Cable Consulting International. Page 10 refers to Double circuit capacities. http://www.theiet.org/factfiles/transmission-report.cfm

1.4 AC Technology Capital Cost Estimates

1.4.1 Table D.1 shows the category sizes that are relevant for AC technology circuit designs:

Table D.1 – AC Technology Circuit Designs

Category	Design	Rating
Lo	Two AC circuits of 1,595 MVA	3,190 MVA
Med	Two AC circuits of 3,190 MVA	6,380 MVA
Hi	Two AC circuits of 3,465 MVA	6,930 MVA

1.4.2 Table D.2 provides a summary of technology configuration and capital cost information (in financial year 2020/21 prices) for each of the AC technology options that National Grid considers as part of an appraisal of Strategic Options.

Table D.2 - AC Technology Configuration and National Grid Capital Costs by Rating

IET, PB/CCI Report short-form label	Circuit Ratings by Voltage		Technology Configuration			Capital Costs		
	275 kV AC Technologies	400 kV AC Technologies	Overhead Line (OHL)	AC Underground Cable (AC Cable)	Gas Insulated Line (GIL)	Overhead Line (OHL)	AC Underground Cable (AC Cable)	Gas Insulated Line (GIL)
	Total rating for two Circuits (2 x rating of each circuit)	Total rating for two Circuits (2 x rating of each circuit)	No. of Conductors Sets “bundles” on each arm/circuit of a pylon	No. of Cables per phase	No of direct buried GIL tubes per phase	Cost for a “double” two circuit pylon route (Cost per circuit, of a double circuit pylon route)	Cost for a two circuit AC cable route (Cost per circuit, of a two circuit AC cable route)	Cost for a two circuit GIL route (Cost per circuit, of a two circuit GIL route)
Lo	3190MVA (2 x 1595MVA) [2000MVA 2 x 1000MVA for AC Cable only]	3190MVA (2 x 1595MVA)	2 conductor sets per circuit (6 conductors per circuit)	1 Cable per Phase (3 cables per circuit)	1 tube per phase (3 standard GIL tubes per circuit)	£3.31m/km (£1.66m/km)	£16.35m/km (£8.17m/km)	£26.81m/km (£13.411m/km)
Med	N/A [3190MVA 2 x 1595MVA for AC Cable only]	6380MVA (2 x 3190MVA)	2 conductor sets per circuit (6 conductors per circuit)	2 Cables per Phase (6 cables per circuit)	1 tube per phase (3 “developing” new large GIL tubes per circuit)	£3.64m/km (£1.82m/km)	£28.32m/km (£14.16m/km)	£31.13m/km (£15.56m/km)
Hi	N/A	6930MVA (2 x 3465MVA)	3 conductor sets per circuit (9 conductors per circuit)	3 Cables per Phase (9 cables per circuit)	2 tubes per phase (6 standard GIL tubes per circuit)	£3.98m/km (£1.99m/km)	£39.89m/km (£19.95m/km)	£43.25m/km (£21.63m/km)

Notes: -

1. Capital Costs for all technologies are based upon rural/arable land installation with no major obstacles (examples of major obstacles would be Roads, Rivers, Railways etc…)
2. All underground AC Cable and GIL technology costs are for direct buried installations only. AC cable and GIL Tunnel installations would have a higher capital installation cost than direct buried rural installations. However, AC cable or GIL replacement costs following the end of conductor life would benefit from re-use of the tunnel infrastructure.
3. AC cable installation costs exclude the cost of reactors and mid point switching stations, which are described later in this appendix.
4. 275 kV circuits will often require Super-Grid Transformers (SGT) to allow connection into the 400 kV system, SGT capital costs are not included above but described later in this appendix.
5. 275 kV AC cable installations above 1000MVA, as indicated in the table above, would require 2 cables per phase to be installed to achieve ratings of 1595MVA per circuit at 275 kV.

1.4.3 Table D.2 provides a summary of the capital costs associated with the key[17] components of transmission circuits for each technology option. Additional equipment is required for technology configurations that include new:

- AC underground cable circuits; and
- Connections between 400 kV and 275 kV parts of the National Grid's transmission system.

1.4.4 The following sections provide an overview of the additional requirements associated with each of these technology options and indicative capital costs of additional equipment.

1.5 AC Underground Cable additional equipment

1.5.1 Appendix C of this Report provides a summary of the electrical characteristics of AC underground cable systems and explains that reactive gain occurs on AC underground cables.

1.5.2 Table D.3 provides a summary of the typical reactive gain within AC underground cable circuits forming part of the National Grid's transmission system.

Table D.3 – Reactive Gain Within AC underground cable circuits

Category	Voltage	Design	Reactive Gain per circuit
Lo	275 kV	One 2500 mm^2 cable per phase	5 Mvar/km
Med	275 kV	Two 2500 mm^2 cable per phase	10 Mvar/km
Lo	400 kV	One 2500 mm^2 cable per phase	10 Mvar/km
Med	400 kV	Two 2500 mm^2 cable per phase	20 Mvar/km
Hi	400 kV	Three 2500 mm^2 cable per phase	30 Mvar/km

1.5.3 National Grid is required to ensure that reactive gain on any circuit that forms part of its transmission system does not exceed 225 Mvar. Above this limit, reactive gain would lead to unacceptable voltages (voltage requirements as defined in the NETS SQSS). In order to manage reactive gain and therefore voltages, reactors are installed on AC underground cable circuits to ensure that reactive gain in total is less than 225 Mvar.

1.5.4 For example a 50 km "Med" double circuit would have an overall reactive gain of 1000 Mvar per circuit (2000 Mvar in total for two circuits). The standard shunt reactor size installed at 400 kV on the National Grid transmission system is 200 Mvar. Therefore four 200 Mvar reactors (800 Mvar) need to be installed on each circuit or eight 200 Mvar

[17] Components that are not required for all technology options are presented separately in this Appendix.

reactors (1600 Mvar) reactors for the two circuits. Each of these reactors cost £8.7m adding £69.6m to an overall cable cost for the example double circuit above.

1.5.5 Mid point switching stations may be required as part of a design to meet the reactive compensation requirements for AC underground cable circuit. The need for switching stations is dependent upon cable design, location and requirements which cannot be fully defined without detailed design.

1.5.6 For the purposes of economic appraisal of Strategic Options, National Grid includes a cost allowance that reflects typical requirements for switching stations. These allowances shown in Table D.4 are:

Table D.4 – Reactive Gain Within AC underground cable circuits

Category	Switching Station Requirement
Lo	Reactive Switching Station every 60 km between substations
Med	Reactive Switching Station every 30 km between substations
Hi	Reactive Switching Station every 20 km between substations

1.5.7 It is noted that more detailed design of AC underground cable systems may require a switching station after a shorter or longer distance than the typical values used by National Grid at the initial appraisal stage.

1.5.8 Table D.5 below shows the capital cost associated with AC underground cable additional equipment.

Table D.5 – Additional costs associated with AC underground cables

Category	Cost per mid point switching station	Cost per 200 Mvar reactor
Lo	£15.09m	£8.7m per reactor
Med	£18.44m	
Hi	£18.44m	

1.6 Connections between AC 275 kV and 400 kV circuits additional equipment

1.6.1 Equipment that transform voltages between 275 kV and 400 kV (a 400/275 kV supergrid transformer or “SGT”) is required for any new 275 kV circuit that connects to a 400 kV part of the National Grid’s transmission system (and vice versa). The number of supergrid transformers needed is dependent on the capacity of the new circuit. National Grid can estimate the number of SGTs required as part of an indicative scope of works that is used for the initial appraisal of Strategic Options.

1.6.2 Table D.6 below shows the capital cost associated with the SGT requirements.

Table D.6 – Additional costs associated with 275 kV circuits requiring connection to the 400 kV system

275 kV Equipment	Capital Cost (SGT - including civil engineering work)
400/275 kV SGT 1100MVA (excluding switchgear)	£7.75m per SGT

1.7 High Voltage Direct Current (“HVDC”) Capital Cost Estimates

1.7.1 Conventional HVDC technology sizes are not easily translated into the “Lo”, “Med” and “Hi” ratings suggested in the IET, PB/CCI report. Whilst National Grid information for HVDC is presented for each of these categories, there are differences in the circuit capacity levels. As part of an initial appraisal, National Grid’s assessment is based on a standard 2 GW converter size. Higher ratings are achievable using multiple circuits.

1.7.2 The capital costs of HVDC installations can be much higher than for equivalent AC overhead line transmission routes. Each individual HVDC link, between each converter station, requires its own dedicated set of HVDC cables. HVDC may be more economic than equivalent AC overhead lines where the route length is many hundreds of kilometres.

1.7.3 Table D.7 provides a summary of technology configuration and capital cost information (in financial year 2020/21 prices) for each of the HVDC technology options that National Grid considers as part of an appraisal of Strategic Options.

Table D.7 - HVDC Technology Capital Costs for 2 GW installations

HVDC Converter Type	2 GW Total HVDC Link Converter Costs (Converter Cost at Each End)	2 GW DC Cable Pair Cost
Current Source Technology or “Classic” HVDC	£475m HVDC link cost (£237.5m at each end)	£3.09m/km VDC
Voltage Source Technology HVDC	£534.38m HVDC link cost (£267.19m at each end)	£3.09m/km

1.7.4 Notes:

- Sometimes a different HVDC capacity (different from the required AC capacity) can be utilised for a project due to the different way HVDC technology can control power flow. The capacity requirements for HVDC circuits will be specified in any option considering HVDC. The cost shall be based upon Table C.4 above.
- Where a single HVDC Link is proposed as an option, to maintain compliance with the NETS SQSS, there may be a requirement to install an additional “Earth Return” DC cable. For example a 2 GW Link must be capable of operating at ½ its capacity i.e. 1 GW during maintenance or following a cable fault. To allow this operation the additional cable known as an “Earth Return” must be installed, this increases cable costs by a further 50% to £4.6m/km.

- Capital Costs for HVDC cable installations are based upon subsea or rural/arable land installation with no major obstacles (examples of major obstacles would be Subsea Pipelines, Roads, Rivers, Railways etc…)

1.7.5 Costs can be adjusted from this table to achieve equivalent circuit ratings where required. For example a "Lo" rating 3190 MW would require two HVDC links of (1.6 GW capacity each), while "Med" and "Hi" rating 6380 MW-6930 MW would require three links with technology stretch of (2.1-2.3 GW each).

1.7.6 Converter costs at each end can also be adjusted, by Linear scaling, from the cost information in Table D.7, to reflect the size of the HVDC link being appraised. HVDC Cable costs are normally left unaltered, as operating at the higher load does not have a large impact the cable costs per km.

1.7.7 The capacity of HVDC circuits assessed for this Report is not always exactly equivalent to capacity of AC circuits assessed. However, Table D.8 below illustrates how comparisons may be drawn using scaling methodology outlined above.

Table D.8 – Illustrative example using scaled 2 GW HVDC costs to match equivalent AC ratings (only required where HVDC requirements match AC technology circuit capacity requirements)

IET, PB/CCI Report short-form label	Converter Requirements (Circuit Rating)	Total Cable Costs/km (Cable Cost per link)	CSC "Classic" HVDC Total Converter Capital Cost (Total Converter cost per end)	VSC HVDC Total Converter Capital Cost (Total Converter cost per end)
Lo	2 x 1.6 GW HVDC Links (3190 MW)	£5.82m/km (2 x £2.91/km)	£704m (4 x £176m [4 converters 2 each end])	(4 x £736m (4 x £184m [4 converters 2 each end])
Med	3 x 2.1* GW HVDC Links (6380 MW)	£9.27m/km (3 x £3.09/km)	£1422m (6 x £237m [6 converters 3 each end])	£1602m (6 x £267m [6 converters 3 each end])
Hi	3 x 2.3* GW HVDC Links (6930 MW)	£10.32m/km (3 x £3.44/km)	£1818m (6 x £303m [6 converters 3 each end])	£1890m (6 x £315m [6 converter 3 each end])

1.7.8 Notes:

- Costs based on 2 GW costs shown in Table C.4 and table shows how HVDC costs are estimated based upon HVDC capacity required for each option.
- Scaling can be used to estimate costs for any size of HVDC link required.
- *Current subsea cable technology for VSC design restricted to 2 GW, so above examples illustrative if technology should become available.

1.8 Indication of Technology end of design life replacement impact

1.8.1 It is unusual for a part of National Grid's transmission system to be decommissioned and the site reinstated. In general, assets will be replaced towards the end of the assets design life. Typically, transmission assets will be decommissioned and removed only as part of an upgrade or replacement by different assets.

1.8.2 National Grid does not take account of replacement costs in the lifetime cost assessment.

1.8.3 National Grid's asset replacement decisions take account of actual asset condition. This may lead to actual life of any technology being longer or shorter than the design life, depending on the environment it is installed in, lifetime loading, equipment family failures among other factors for example.

1.8.4 The following provides a high level summary of common replacement requirements applicable to specific technology options:

- OHL - Based on the design life of component parts, National Grid assumes an initial design life of around 40 years for overhead line circuits. After the initial 40 year life of an overhead line circuit, substantial pylon replacement works would not normally be required. The cost of Pylons is reflected in the initial indicative capital costs, but the cost of replacement at 40 years would not include the pylon cost. As pylons have an 80 year life and can be re-used to carry new replacement conductors. The replacement costs for overhead line circuits at the end of their initial design life are assessed by National Grid as being around 50% of the initial capital cost, through the re-use of pylons.
- AC underground Cable - At the end of their initial design life, circa 40 years, replacement costs for underground cables are estimated to be equal or potentially slightly greater than the initial capital cost. This is because of works being required to excavate and remove old cables prior to installing new cables in their place in some instances.
- GIL - At the end of the initial design life, circa 40 years, estimated replacement costs for underground GIL would be equal to or potentially greater than the initial capital cost. This is because of works being required to excavate and remove GIL prior to installing new GIL in their place in some instances.
- HVDC - It should be noted at the end of the initial design life, circa 40 years, replacement costs for HVDC are significant. This due to the large capital costs for the replacement of converter stations and the cost of replacing underground or subsea DC cables when required.

1.9 Net Present Value Cost Estimates

1.9.1 At the initial appraisal stage, National Grid prepares estimates of the costs that are expected to be incurred during the design lifetime of the new assets. National Grid considers costs associated with:

- Operation and maintenance
- Electrical losses

1.9.2 For both categories, NPV calculations are carried out using annual cost estimates and a generic percentage discount rate over the design life period associated with the technology option being considered.

1.9.3 The design life for all technology equipment is outlined in the technology description in Appendix C. The majority of expected design lives are of the order of 40 years, which is used to assess the following NPV cost estimates below.

1.9.4 In general discount rates used in NPV calculations would be expected to reflect the normal rate of return for the investor. National Grid's current rate of return is 6.25%. However, the Treasury Green Book recommends a rate of 3.5% for the reasons set out below[18]

"The discount rate is used to convert all costs and benefits to 'present values', so that they can be compared. The recommended discount rate is 3.5%. Calculating the present value of the differences between the streams of costs and benefits provides the net present value (NPV) of an option. The NPV is the primary criterion for deciding whether government action can be justified."

1.9.5 National Grid considered the impact of using the lower Rate of Return (used by UK Government) on lifetime cost of losses assessments for transmission system investment proposals. Using the rate of 3.5% will discount loss costs, at a lower rate than that of 6.25%. This has the overall effect of increasing the 40 year cost of losses giving a more onerous cost of losses for higher loss technologies.

1.9.6 For the appraisal of Strategic Options, National Grid recognises the value of closer alignment of its NPV calculations with the approach set out by government for critical infrastructure projects.

1.10 Annual Operations and Maintenance Cost

1.10.1 The maintenance costs associated with each technology vary significantly depending upon type. Some electrical equipment is maintained regularly to ensure system performance is maintained. More complex equipment like HVDC converters have a significantly higher cost associated with them, due to their high maintenance requirements for replacement parts. Table D.9 shows the cost of maintenance for each technology, which unlike capital and losses is not dependent on capacity.

[18] http://www.hm-treasury.gov.uk/d/green_book_complete.pdf Paragraph 5.49 on Page 26 recommends a discount rate of 3.5% calculation for NPV is also shown in the foot note of this page.

NPV calculations are carried out using the following equation over the period of consideration.

Dn =1/(1 + r)n

Where Dn = Annual Loss Cost, r = 3.5% and n = 40 years

Table D.9 – Annual maintenance costs by Technology

	Overhead Line (OHL)	**AC Underground Cable (AC Cable)**	**Gas Insulated Line (GIL)**	**High Voltage Direct Current (HVDC)**
Circuit Annual maintenance cost per two circuit km (AC) (Annual cost per circuit Km [AC])	£2,660/km (£1,330/km)	£5,644.45/km (£2,822.22/km)	£2,687.83/km (£1,343.92/km)	£134/km Subsea Cables
Associated equipment Annual Maintenance cost per item	N/A	£6,719.58 per reactor £41,661 per switching station	N/A	£1,300,911 per converter station
Additional costs for 275 kV circuits requiring connection to the 400 kV system				
275/400 kV SGT 1100 MVA Annual maintenance cost per SGT	£6,719.58 per SGT	£6,719.58 per SGT	£6.719.58 per SGT	N/A

1.11 Annual Electrical Losses and Cost

1.11.1 At a system level annual losses on the National Grid electricity system equate to less the 2% of energy transported. This means that over 98% of the energy entering the transmission system from generators/interconnectors reaches the bulk demand substations where the energy transitions to the distribution system. Electricity transmission voltages are used to reduce losses, as more power can be transported with lower currents at transmission level, giving rise to the very efficient loss level achieved of less than 2%. The calculations below are used to show how this translates to a transmission route.

1.11.2 Transmission losses occur in all electrical equipment and are related to the operation and design of the equipment. The main losses within a transmission system come from heating losses associated with the resistance of the electrical circuits, often referred to as I2R losses (the electrical current flowing through the circuit, squared, multiplied by the resistance). As the load (the amount of power each circuit is carrying) increases, the current in the circuit is larger.

1.11.3 The average load of a transmission circuit which is incorporated into the transmission system is estimated to be 34% (known as a circuit average utilisation). This figure is calculated from the analysis of the load on each circuit forming part of National Grid's transmission system over the course of a year. This takes account of varying generation and demand conditions and is an appropriate assumption for the majority of Strategic Options.

1.11.4 This level of circuit utilisation is required because if a fault occurs there needs to be an alternative route to carry power to prevent wide scale loss of electricity for homes, business, towns and cities. Such events would represent a very small part of a circuit's 40 year life, but this availability of alternative routes is an essential requirement at all times to provide secure electricity supplies to the nation.

1.11.5 In all AC technologies the power losses are calculated directly from the electrical resistance and impedance properties of each technology and associated equipment. Table D.10 provides a summary of circuit resistance data for each AC technology and capacity options considered in this Report.

Table D.10 – AC circuit technologies and associated resistance per circuit

IET, PB/CCI Report short-form label	**AC Overhead Line Conductor Type (complete single circuit resistance for conductor set)**	**AC Underground Cable Type (complete single circuit resistance for conductor set)**	**AC Gas Insulated Line (GIL) Type (complete single circuit resistance for conductor set)**
Lo	2 x 570 mm^2 (0.025 Ω/km)	1 x 2500 mm^2 (0.013 Ω/km*)	Single Tube per phase (0.0086 Ω/km)
Med	2 x 850 mm^2 (0.0184 Ω/km)	2 x 2500 mm^2 (0.0065 Ω/km*)	Single Tube per phase (0.0086 Ω/km)
Hi	3 x 700 mm^2 (0.014 Ω/km)	3 x 2500 mm^2 (0.0043 Ω/km*)	Two tubes per phase (0.0065 Ω/km)
Losses per 200Mvar Reactor required for AC underground cables			
Reactor Losses	N/A	0.4 MW per reactor	N/A
Additional losses for 275 kV circuits requiring connection to the 400 kV system			
275 kV options only 275/400 kV SGT losses	0.2576 Ω (plus 83 kW of iron losses) per SGT	0.2576 Ω (plus 83 kW of iron losses) per SGT	0.2576 Ω (plus 83 kW of iron losses) per SGT

1.11.6 The process of converting AC power to DC is not 100% efficient. Power losses occur in all elements of the converter station: the valves, transformers, reactive compensation/filtering and auxiliary plant. Manufacturers typically represent these losses in the form of an overall percentage. Table D.11 below shows the typical percentage losses encountered in the conversion process, ignoring losses in the DC cable circuits themselves.

Table D.11 – HVDC circuit technologies and associated resistance per circuit

HVDC Converter Type	2 GW Converter Station losses	2 GW DC Cable Pair Losses	2 GW Total Link loss
Current Source (CSC) Technology or "Classic" HVDC	0.5% per converter	Ignored	1% per HVDC Link
Voltage Source (VSC) Technology HVDC	1.0% per converter	Ignored	2% per HVDC Link

1.11.7 The example calculation explained in detail below is for "Med" category circuits and has been selected to demonstrate the principles of the mathematics set out in this section. This example does not describe specific options set out within this report. A detailed example explanation of the calculations used to calculate AC losses is included in Appendix E.

1.11.8 The circuit category, for options contained within this report, is set out within each option. The example below demonstrates the mathematics and principles, which is equally applicable to "Lo", "Med" and "Hi" category circuits, over any distance.

1.11.9 The example calculations (using calculation methodology described in Appendix E) of instantaneous losses for each technology option for an example circuit of 40 km "Med" capacity 6380 MVA (two x 3190 MVA).

- Overhead Lines = (2 x 3) x 1565.5 A2 x (40 x 0.0184 Ω/km) = 10.8 MW
- Underground Cable = (2 x 3) x1565.5 A^2 x (40 x 0.0065 Ω/km) + (6 x 0.4 MW) = 6.2 MW
- Gas Insulated Lines = (2 x 3) x 1565.5 A2 x (40 x 0.0086 Ω/km) = 5.1 MW
- CSC HVDC = 34% x 6380 MW x 1% = 21.7 MW
- VSC HVDC = 34% x 6380 MW x 2% = 43.4 MW

1.11.10 An annual loss figure can be calculated from the instantaneous loss. National Grid multiplies the instantaneous loss figure by the number of hours in a year and also by the cost of energy. National Grid uses £60/MWhr.

1.11.11 The following is a summary of National Grid's example calculations of Annual Losses and Maintenance costs for each technology option for an example circuit of 40 km "Med" capacity 6380 MVA (two x 3190 MVA).

- Overhead Line annual loss = 10.8 MW x 24 x 365 x £60/MWhr = £5.7m.
- U-ground Cable annual loss = 6.2 MW x 24 x 365 x £60/MWhr = £3.3m.
- Gas Insulated lines annual loss = 5.1 MW x 24 x 365 x £60/MWhr = £2.7m
- CSC HVDC annual loss = 21.7 MW x 24 x 365 x £60/MWhr = £11.4m
- VSC HVDC annual loss = 43.4 MW x 24 x 365 x £60/MWhr = £22.8m

1.12 Example Lifetime costs and NPV Cost Estimate

1.12.1 The annual Operation, Maintenance and loss information is assessed against the NPV model at 3.5% over 40 years and added to the capital costs to provide a lifetime cost for each technology.

1.12.2 Table D.12 shows an example for a “Med” capacity route 6380 MVA (2 x 3190 MVA) 400 kV, 40 km in length over 40 years.

Table D.12 – Example Lifetime Cost table (rounded to the nearest £m)

Example 400 kV “Med” Capacity over 40 km	Overhead Line (OHL)	AC Underground Cable (AC Cable)	Gas Insulated Line (GIL)	CSC High Voltage Direct Current (HVDC)	VSC High Voltage Direct Current (HVDC)
Capital Cost	£145.6m	£1167.6m	£1,244.8m	£1,795.8m	£1,973.9m
NPV Loss Cost over 40 years at 3.5% discount rate	£125m	£62.6m	£58.4m	£235.6m	£471.2m
NPV Maintenance Cost over 40 years at 3.5% discount rate	£2.33m	£5.5m	£2.4m	£171.7m	£171.7m
Lifetime Cost	£273m	£1,236m	£1,306m	£2,203m	£2,617m

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Appendix E Mathematical Principles used for AC Loss Calculation

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1.1 Introduction

1.1.1 This Appendix provides a detailed description of the mathematical formulae and principles that National Grid applies when calculating transmission system losses. The calculations use recognised mathematical equations which can be found in power system analysis text books.

1.1.2 The example calculation explained in detail below is for "Med" category circuits and has been selected to demonstrate the principles of the mathematics set out in this section. This example does not describe specific options set out within this report.

1.1.3 The circuit category, for options contained within this report, is set out within each option. The example below demonstrates the mathematics and principles, which is equally applicable to "Lo", "Med" and "Hi" category circuits, over any distance.

1.2 Example Loss Calculation (1) – 40 km 400 kV "Med" Category Circuits

1.2.1 The following is an example loss calculation for a 40 km 400 kV "Med" category (capacity of 6,380 MVA made up of two 3,190 MVA circuits).

1.2.2 Firstly, the current flowing in each of the two circuits is calculated from the three phase power equation of $P= \sqrt{3}V_{LL}I_{LL} \cos\theta$. Assuming a unity power factor ($\cos\theta= 1$), the current in each circuit can be calculated using a rearranged form of the three phase power equation of:

(In a star (Y) configuration electrical system $I = I_{LL} = I_{LN}$)

$I = P/\sqrt{3}V_{LL}$

Where, P is the circuit utilisation power, which is 34% of circuit rating as set out in D.40 of Appendix D, which for the each of the two circuits in the "Med" category example is calculated as:

$P = 34\% \times 3190 \text{ MVA} = 1{,}084.6 \text{ MVA}$

and, V_{LL} is the line to line voltage which for this example is 400 kV.

For this example, the average current flowing in each of the two circuits is:

$I = 1{,}084.6 \times 106/(\sqrt{3} \times 400 \times 103) = 1{,}565.5 \text{ Amps}$

1.2.3 The current calculated above will flow in each of the phases of the three phase circuit. Therefore from this value it is possible to calculate the instantaneous loss which occurs at the 34% utilisation loading factor against circuit rating for any AC technology.

1.2.4 For this "Med" category example, the total resistance for each technology option is calculated (from information in Appendix D, Table D.10) as follows:

Overhead Line = 0.0184Ω/km x 40 km = 0.736 Ω

Cable Circuit[19] = 0.0065Ω/km x 40 km = 0.26 Ω

[19] A 40 km three phase underground cable circuit will also require three reactors to ensure that reactive gain is managed within required limits.

Gas Insulated Line = 0.0086Ω/km x 40 km = 0.344 Ω

These circuit resistance values are the total resistance seen in each phase of that particular technology taking account the number of conductors needed for each technology option.

1.2.5 The following is a total instantaneous loss calculation for the underground cable technology option for the “Med” category example:

Losses per phase are calculated using $P=I^2R$

1,565.52 x 0.26 = 0.64 MW

Losses per circuit are calculated using $P=3I^2R$

3 x 1,565.52 x 0.26 = 1.91 MW

Losses for “Med” category are calculated by multiplying losses per circuit by number of circuits in the category.

2 x 1.91 MW = 3.8 MW

1.2.6 For underground cable circuits, three reactors per circuit are required (six in total for the two circuits in the “Med” category). Each of these reactors has a loss of 0.4 MW. The total instantaneous losses for this “Med” category example with the underground cable technology option are assessed as:

3.8 + (6 x 0.4) = 6.2 MW

1.2.7 The same methodology is applied for the other AC technology option types for the “Med” category example considered in this Appendix. The following is a summary of the instantaneous total losses that were assessed for each technology option:

Overhead Lines = (2 x 3) x 1,565.52 x 0.736 = 10.8 MW

Cables = (2 x 3) x 1,565.52 x 0.26 + (6 x 0.4) = 6.2 MW

Gas Insulated Lines = (2 x 3) x 1,565.52 x 0.344 = 5.1 MW

1.3 Example Loss Calculation (2) – 40 km 275 kV “Lo” Category Circuits Connecting to a 400 kV part of the National Grid’s transmission system

1.3.1 The following is an example loss calculation for a 40 km 275 kV “Lo” category (capacity of 3,190 MVA made up of two 1,595 MVA circuits) and includes details of how losses of the supergrid transformer (“SGT”) connections to 400 kV circuits are assessed. This example assesses the losses associated with the GIL technology option up to a connection point to the 400 kV system.

1.3.2 The circuit utilisation power (P) which for the each of the two circuits in the “Lo” category example is calculated as:

P = 34% x 1,595 = 542.3 MVA

For this example, the average current flowing in each of the two circuits is:

$I = 542.3 \times 10^6 / (\sqrt{3} \times 275 \times 10^3) = 1{,}138.5$ Amps

1.3.3 For this “Lo” category example, the total resistance for the GIL technology option is calculated (from information in Appendix D, Table D.10) as follows:

$$0.0086\Omega/\text{km} \times 40 \text{ km} = 0.344\ \Omega$$

1.3.4 The following is a total instantaneous loss calculation for the GIL technology option for this “Lo” category example:

Losses per circuit are calculated using $P=3I^2R$

3 x 1138.5 x 0.344 = 1.35 MW

Losses for “Lo” category 275 kV circuits are calculated by multiplying losses per circuit by number of circuits in the category

2 x 1.35 MW = 2.7 MW

1.3.5 SGT losses also need to be included as part of the assessment for this “Lo” category example which includes connection to 400 kV circuits. SGT resistance[20] is calculated (from information in Appendix D, Table D.10) as 0.2576 Ω.

1.3.6 The following is a total instantaneous loss calculation for the SGT connection part of this “Lo” category example:

The average current flowing in each of the two SGT 400 kV winding are calculated as:

$$I_{HV} = 542.3 \times 10^6/(\sqrt{3} \times 400\times10^3) = 782.7 \text{ Amps}$$

Losses per SGT are calculated using $P=3I^2R$

SGT Loss = 3 x 782.7 x 0.2576 = 0.475 MW

Iron Losses in each SGT = 84kW

Total SGT instantaneous loss (one SGT per GIL circuit) = (2 x 0.475) + (2 x 0.084) = 1.1 MW.

1.3.7 For this example, the total “Lo” category loss is the sum of the calculated GIL and SGT total loss figures:

“Lo” category loss = 2.7 + 1.1 = 3.8 MW

[20] Resistance value referred to the 400 kV side of the transformer.

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Appendix F Glossary of Terms and Acronyms

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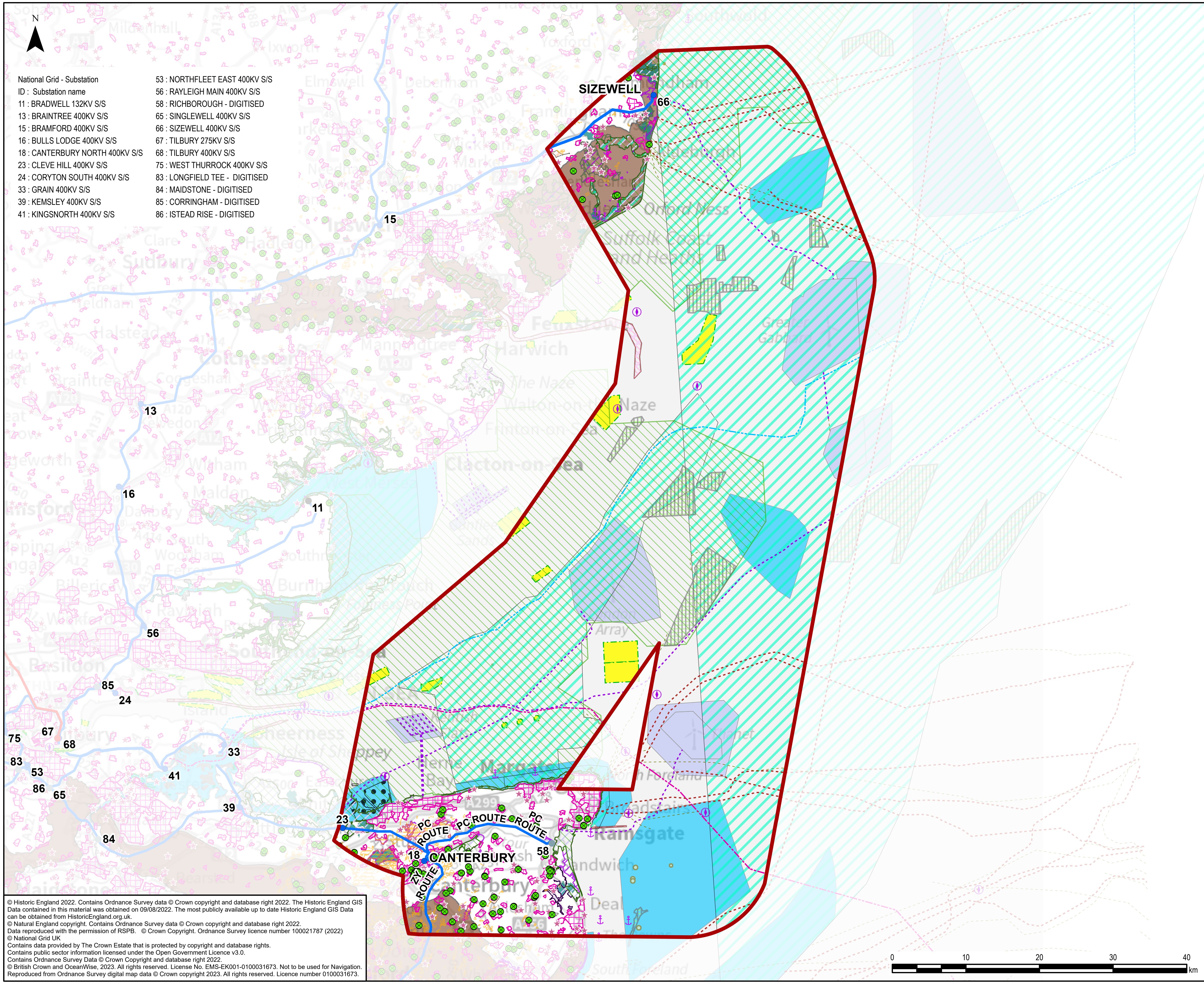
AC		Alternating Current
AC Cable		AC Underground Cable
Conductor		used to transport power
CSC		Current Source Converter
DC		Direct Current
DCO		Development Consent Order issued under the Planning Act 2008
Electricity Act		The Electricity Act 1989
EN-1		Overarching National Policy Statement for Energy
EN-3		National Policy Statement for Renewable Energy Infrastructure
EN-5		National Policy Statement for Electricity Network Infrastructure
EN-6		National Policy Statement for Nuclear Power Generation
GIL		Gas Insulated Lines
HVDC		High Voltage Direct Current
IET, PB/CCI Report		An independent report endorsed by the Institution of Engineering and Technology by Parsons Brinckerhoff in association with Cable Consulting International
Insulators		used to safely connect conductors to pylons
IPC		Infrastructure Planning Commission
National Grid		National Grid Electricity Transmission plc
NPV		Net Present Value
NETS SQSS		National Electricity Transmission System Security and Quality of Supply Standard
NGESO		Operator of National Electricity Transmission System
NPS		National Policy Statements
NSIP		Nationally Significant Infrastructure Project
Ofgem		The Office of Gas and Electricity Markets
OHL		Overhead Line
(the) Policy		National Grid's Stakeholder, Community and Amenity Policy
Pylons		used to support conductors
RIBA		Royal Institute of British Architects

SF_6		Sulphur Hexafluoride (gas used to provide electrical insulation)
Span length		distance between adjacent pylons
STC		System Operator – Transmission Owner Code
SGT		Super-Grid Transformer
The Authority		Gas and Electricity Markets Authority, the governing body of Ofgem
T-pylon		monopole pylon design developed by National Grid
Transmission Licence		Licence granted under Section 6(1)(b) of the Electricity Act
volt (V)		The electrical unit of potential difference 1 kilovolt (kV) = 1,000 volts
watt (W)		The SI unit of power 1 kilowatt (kW) = 1,000 watts 1 megawatt (MW) = 1,000 kW 1 gigawatt (GW) = 1,000 MW
XLPE		Cross Linked Polyethylene (solid material used to provide electrical insulation)

Appendix G Appraisal study areas



LEGEND

National Grid - Overhead
- 400kV
- 275kV

National Grid - Substation
- 400kV
- 132kV
- 275kV
- Other
- Study Area

Anchorage Point
- Anchorage area
- Pilot boarding place

Listed Building
- Grade I
- Mooring Cable
- Power line
- Telephone
- Undefined
- GridLink Proposed Route
- NeuConnect Proposed Route
- Ancient Woodland

Registered Parks and Gardens
- Grade I
- Grade II
- Grade II*
- Ramsar
- Special Protection Area (SPA)
- SAC with Marine Components
- Site of Special Scientific Interest (SSSI)
- Anchorage area
- Dredged Channel
- Urban Settlement (DCLG OS Dataset)
- Aquaculture
- Protected Wreck
- World Heritage Site
- Area of Natural Beauty (AONB)
- Scheduled Monument Location
- Scheduled Monument Boundary
- Marine Conservation Zone (MCZ)
- RSPB Reserve
- Offshore Wind Farm
- Minerals Aggregate

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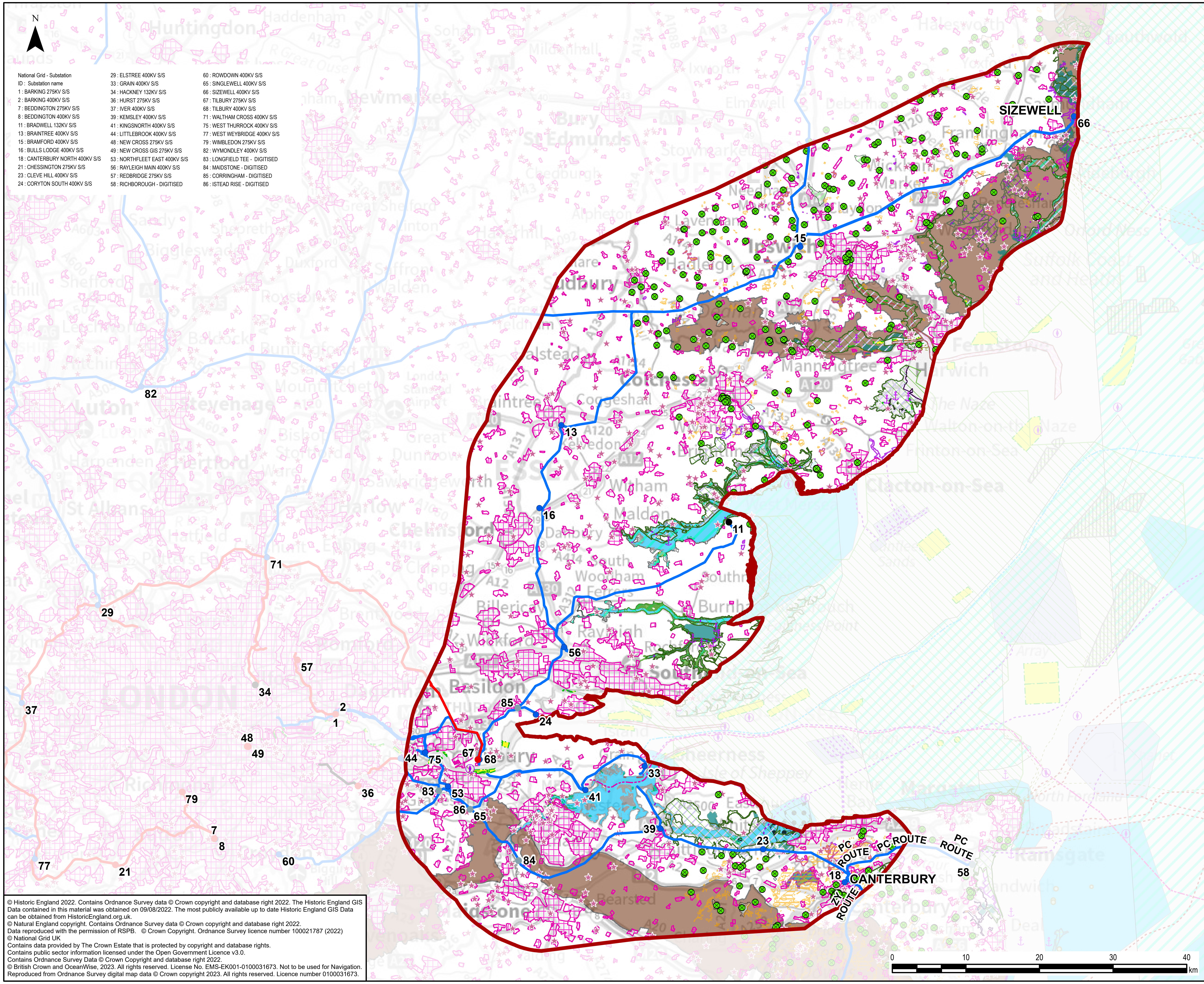

LEGEND

National Grid - Overhead
- 400kV
- 275kV
- 132kV

National Grid - Substation
- 400kV
- 132kV
- 275kV
- Other

Study Area

Anchorage Point
- Anchorage area
- Pilot boarding place

Listed Building
- Grade I

Mooring Cable
Power line
Telephone
Undefined
GridLink Proposed Route
NeuConnect Proposed Route
Ancient Woodland

Registered Parks and Gardens
- Grade I
- Grade II
- Grade II*

Ramsar
Special Protection Area (SPA)
SAC with Marine Components
Site of Special Scientific Interest (SSSI)
Anchorage area
Dredged Channel
Urban Settlement (DCLG OS Dataset)
Aquaculture
Protected Wreck
World Heritage Site
Area of Natural Beauty (AONB)
Scheduled Monument Location
Scheduled Monument Boundary
Marine Conservation Zone (MCZ)
RSPB Reserve
Offshore Wind Farm
Minerals Aggregate

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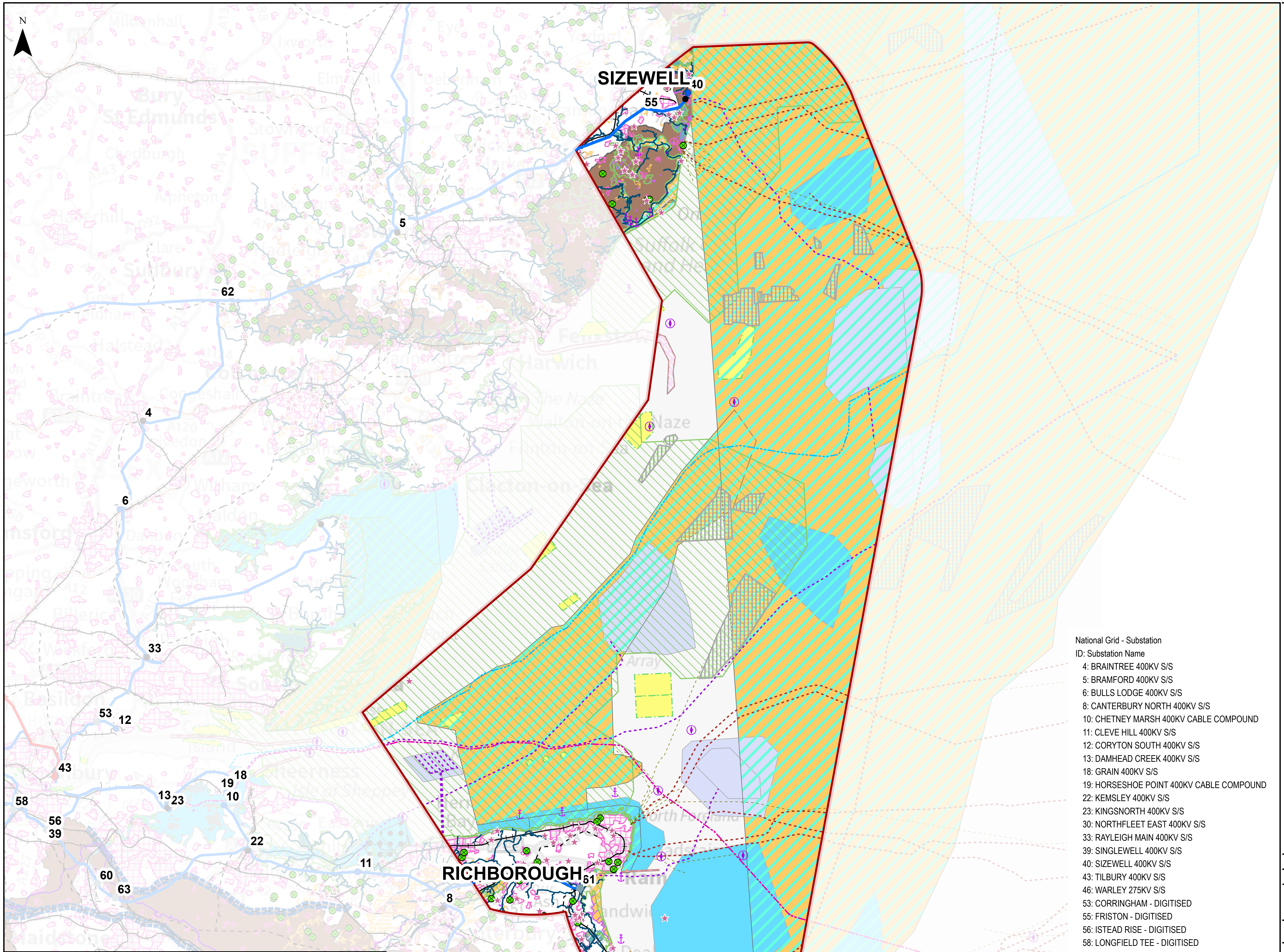

National Grid - Substation
ID: Substation Name
4: BRAINTREE 400KV S/S
5: BRAMFORD 400KV S/S
6: BULLS LODGE 400KV S/S
8: CANTERBURY NORTH 400KV S/S
10: CHETNEY MARSH 400KV CABLE COMPOUND
11: CLEVE HILL 400KV S/S
12: CORYTON SOUTH 400KV S/S
13: DAMHEAD CREEK 400KV S/S
18: GRAIN 400KV S/S
19: HORSESHOE POINT 400KV CABLE COMPOUND
22: KEMSLEY 400KV S/S
23: KINGSNORTH 400KV S/S
30: NORTHFLEET EAST 400KV S/S
33: RAYLEIGH MAIN 400KV S/S
39: SINGLEWELL 400KV S/S
40: SIZEWELL 400KV S/S
43: TILBURY 400KV S/S
46: WARLEY 275KV S/S
53: CORRINGHAM - DIGITISED
55: FRISTON - DIGITISED
56: ISTEAD RISE - DIGITISED
58: LONGFIELD TEE - DIGITISED
60: MAIDSTONE - DIGITISED
61: RICHBOROUGH - DIGITISED
62: TWINSTEAD TEE - DIGITISED
63: UNKNOWN - DIGITISED

0 10 20 30 40 50 km

LEGEND

National Grid - Substation
- 400kV
- 275kV
- 132kV
- Other

National Grid - Overhead
- 400kV
- 275kV

Scheduled Monument Location

Listed Building
- Grade I

Anchorage Point
- Anchorage Area
- Pilot Boarding Place

NeuConnect Proposed Route
GridLink Proposed Route

Marine Cable
- Mooring Cable
- Power line
- Telephone
- Undefined

Railway
River
Trunk Road
National Trail
Motorway
Offshore Wind Farm
Aquaculture
Anchorage area
Dredged Channel
Marine Conservation Zone (MCZ)
Minerals Aggregate

Registered Parks & Gardens
- Grade I
- Grade II
- Grade II*

Scheduled Monument Boundary
World Heritage Site
Protected Wreck
Ancient Woodland
Special Area of Conservation (SAC)
Special Protection Area (SPA)
Site of Special Scientific Interest (SSSI)
Ramsar
SAC with Marine Components
Area of Outstanding Natural Beauty (AONB)
National Trust - Always Open
National Trust - Limited Access Land
RSPB Reserve
Urban Settlement (DCLG OS Dataset)

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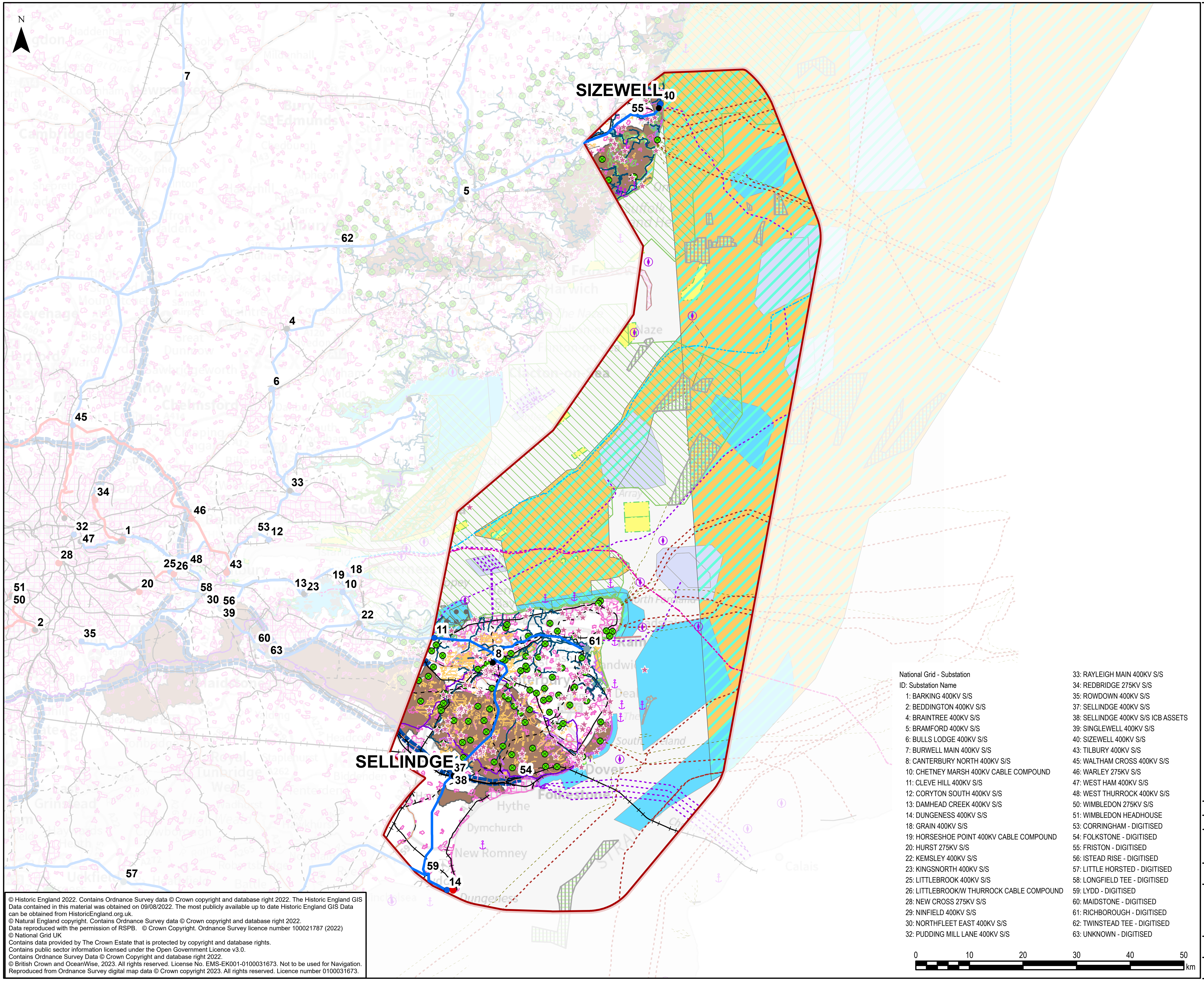

National Grid - Substation
ID: Substation Name

1: BARKING 400KV S/S
2: BEDDINGTON 400KV S/S
4: BRAINTREE 400KV S/S
5: BRAMFORD 400KV S/S
6: BULLS LODGE 400KV S/S
7: BURWELL MAIN 400KV S/S
8: CANTERBURY NORTH 400KV S/S
10: CHETNEY MARSH 400KV CABLE COMPOUND
11: CLEVE HILL 400KV S/S
12: CORYTON SOUTH 400KV S/S
13: DAMHEAD CREEK 400KV S/S
14: DUNGENESS 400KV S/S
18: GRAIN 400KV S/S
19: HORSESHOE POINT 400KV CABLE COMPOUND
20: HURST 275KV S/S
22: KEMSLEY 400KV S/S
23: KINGSNORTH 400KV S/S
25: LITTLEBROOK 400KV S/S
26: LITTLEBROOK/W THURROCK CABLE COMPOUND
28: NEW CROSS 275KV S/S
29: NINFIELD 400KV S/S
30: NORTHFLEET EAST 400KV S/S
32: PUDDING MILL LANE 400KV S/S
33: RAYLEIGH MAIN 400KV S/S
34: REDBRIDGE 275KV S/S
35: ROWDOWN 400KV S/S
37: SELLINDGE 400KV S/S
38: SELLINDGE 400KV S/S ICB ASSETS
39: SINGLEWELL 400KV S/S
40: SIZEWELL 400KV S/S
43: TILBURY 400KV S/S
45: WALTHAM CROSS 400KV S/S
46: WARLEY 275KV S/S
47: WEST HAM 400KV S/S
48: WEST THURROCK 400KV S/S
50: WIMBLEDON 275KV S/S
51: WIMBLEDON HEADHOUSE
53: CORRINGHAM - DIGITISED
54: FOLKSTONE - DIGITISED
55: FRISTON - DIGITISED
56: ISTEAD RISE - DIGITISED
57: LITTLE HORSTED - DIGITISED
58: LONGFIELD TEE - DIGITISED
59: LYDD - DIGITISED
60: MAIDSTONE - DIGITISED
61: RICHBOROUGH - DIGITISED
62: TWINSTEAD TEE - DIGITISED
63: UNKNOWN - DIGITISED

LEGEND

National Grid - Substation
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- 132kV
- Other

National Grid - Overhead
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- 132kV
- Scheduled Monument Location

Listed Building
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Anchorage Point
- Anchorage Area
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- NeuConnect Proposed Route
- GridLink Proposed Route

Marine Cable
- Mooring Cable
- Power line
- Telephone
- Undefined
- Railway
- River
- Trunk Road
- National Trail
- Motorway
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- SAC with Marine Components
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- National Park
- Urban Settlement (DCLG OS Dataset)

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