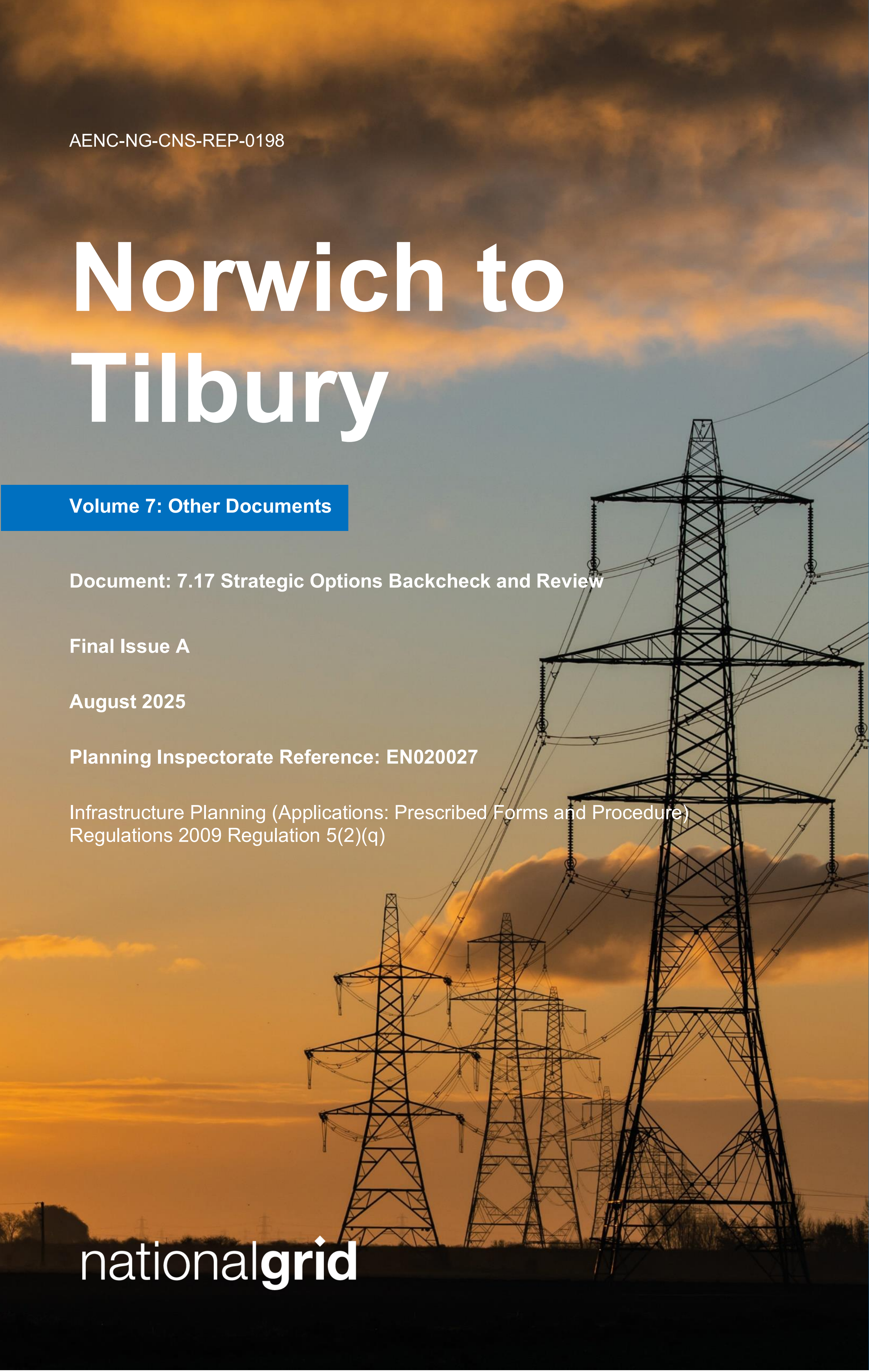

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Norwich to Tilbury

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Contents

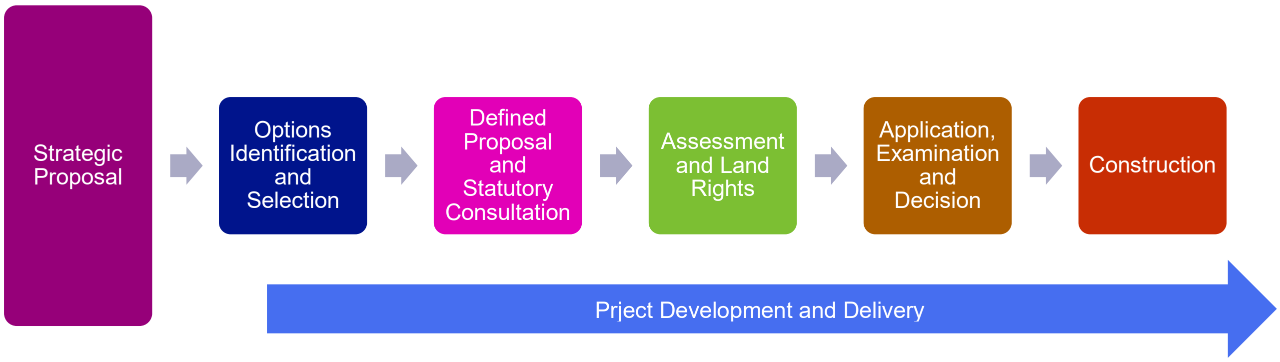
Executive summary

Purpose of this report

This version of the Strategic Options Backcheck and Review, post statutory consultation, has been prepared by National Grid Electricity Transmission plc (NGET) and addresses the backcheck and review of the strategic options considered for the Norwich to Tilbury project in East Anglia against the need case.

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

Figure ES1 Approach to consenting process



This report forms part of the initial 'Options identification and selection' stage and 'defined proposal and statutory consultation' stage.

This executive summary provides an overview of the contents of this report and highlights key areas relevant to this project.

National Grid Electricity Transmission (NGET)

National Grid Electricity Transmission (NGET) 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.

NGET, 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 1989.

National Energy System Operator (NESO)

The National Energy System Operator (NESO) is the electricity system operator for Great Britain. NESO ensures electricity is always where it is needed, and the transmission network remains stable and secure in its operation.

As of 1 October 2024, NESO became a public body owned by the Department for Energy Security and Net Zero (DESNZ). It was formerly part of National Grid PLC and called the Electricity System Operator (ESO).

NESO has been established to act as the independent organisation responsible for planning Great Britian's energy system, looking after and operating the electricity and gas networks while also offering expert advice to the sector's decision-makers.

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 have 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 Southeast 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 50GW of offshore wind by 2030's as a key part of a strategy for secure, clean and affordable British energy for the long term.

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 132kV connected gas fired power stations.

This generation capacity has recently been added to by several offshore windfarms with the existing generation totalling 6,552.4 MW of installed capacity. This is expected to grow substantially in coming years. In the East Anglia region, connection agreements have been signed for 26,919.9 MW of new generation (total generation of 33,472.3 MW minus Existing Generation of 6,552.4 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).

Peak demand by 2030/31 is anticipated to be approximately 1,281 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 demand.

Without reinforcement, the capacity of the East Anglia and Southeast existing network is insufficient to accommodate the connection of the proposed new power sources. The 'Thermal

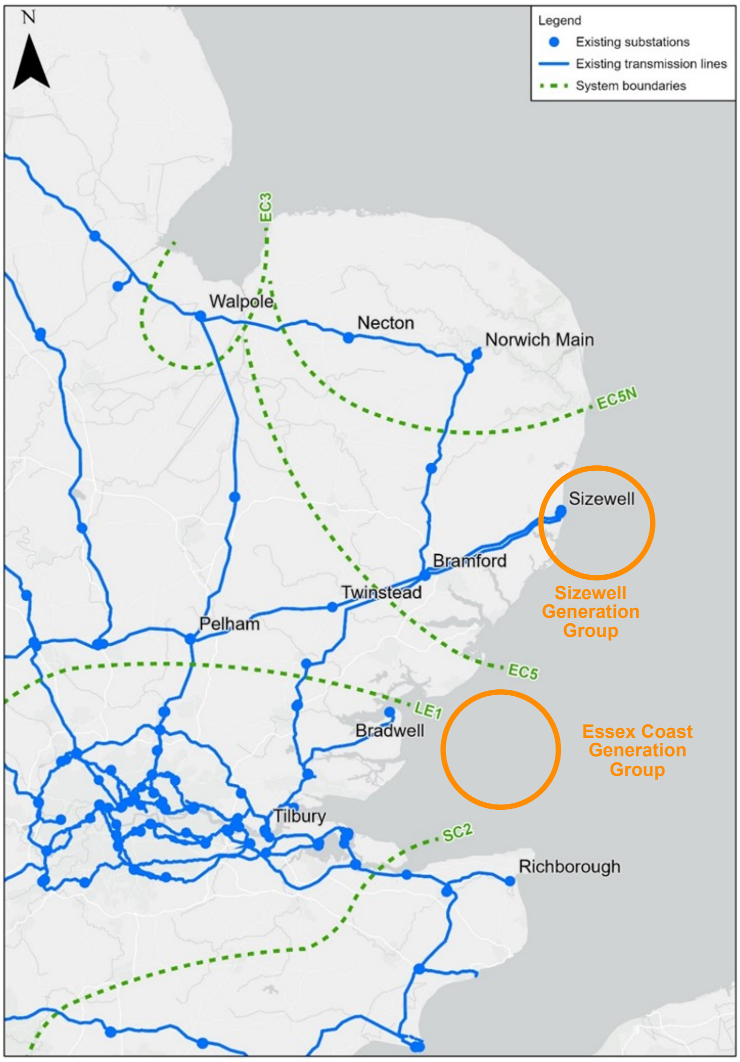
Boundary Export Limit' – the physical maximum energy capacity the system can accommodate during planned system faults – would be exceeded, preventing export of power to demand centres beyond East Anglia. In these circumstances, generators connecting in the area would be required to reduce their output 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.

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 Southeast are EC3, EC5N, EC5, LE1 and SC2. The relevant Generation Groups are Sizewell and Essex coast. These are illustrated in the network diagram in Figure ES2 below. This Figure includes the Bramford to Twinstead Reinforcement project, that was granted development consent in September 2024, and which is now under construction.

Figure ES2 East Anglia and South-East region transmission system and system boundaries



We have assessed the possible impacts associated with the connection of the total volume of new generation on these 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 to accommodate contracted generation up to 2037 would be between 23,232.4 MW and 24,834.7 MW export across EC5. 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 assumes 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 4365.0 MW and the NETS SQSS requires us to design to the higher of these conditions.

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 9,928 MW of capacity across East Anglia EC5 Boundary and 7,520 MW of capacity across EC5N Boundary
- Provision of 7,476 MW of capacity across the LE1 Boundary
- Provision of 352.1 MW of capacity to the Sizewell Generation Group
- Provision of 3,480 MW of connection capacity from the Essex Coast Generation Group
- Provision of 8,470 MW of capacity from the SC2 Boundary Group.
- In summary, this analysis shows that without reinforcement, the capacity of the East Anglia existing network is insufficient to accommodate the connection of proposed new power sources connecting in the area. This need is emphasised by the analysis of the NESO, which has recommended consecutive 'proceed' signals to new 400 kV circuits in north and Southeast Anglia in NESO Beyond 2030 report, meaning that it considers the project part of the need to meet the UK Government's 2030 offshore wind targets.
- We are therefore required to assess the reinforcement options available for providing the additional capability required.

Initial strategic options analysis

In 2022, as part of the wider Network Planning Process, we carried out an initial assessment of the strategic options available to meet the need case set out above. This drew on the economic analysis of the ESO in the NOA process and was presented in the April 2022 Corridor and Preliminary Routeing and Siting Study (CPRSS).

This assessment identified 27 combinations of circuit options across a wide geographical area, later reduced to 23 (3 for west, 5 for north and 15 for east). This analysis covered both East Anglia and the Southeast.

For each of these combinations of options we undertook an appraisal of deliverability, considered the system benefit that the reinforcement provided, considered environmental and socioeconomic factors and considered the cost benefit analysis completed by the ESO.

As part of the annual network planning cycle mentioned above, each combination of options proceeded through a NOA Cost Benefit Analysis (CBA) carried out by the ESO. Through this process the ESO makes investment recommendations to transmission owners (TOs) including NGET as to whether there is an economic case for individual reinforcements to proceed. These recommendations are considered by TOs in their assessment of reinforcement options.

The NOA CBA carried out by the ESO compared the combination of options using a 'Least Worst Regrets' method, being ranked in order of the highest (i.e. worst) regret for each option, in comparison to all other options, across the four Future Energy Scenarios (FES) (i.e. if an option was the best in all FES, its Least Worst Regret would be 0). This analysis concluded that the overall Least Worst Regret option across the four FES was a combination of Norwich – Bramford (AENC), Bramford – Tilbury (ATNC), Richborough – Sizewell (SCD1) and Tilbury – Grain (TENC) as shown in Table ES1.

Table ES1 NOA Lead Option as Reported in the CPRSS

AENC	Norwich-Bramford	AC OHL (Onshore)
ATNC	Bramford-Tilbury	AC OHL (Onshore)
SCD1	Richborough-Sizewell	HVDC Cable (Offshore)
TENC	Tilbury-Grain	AC OHL (Onshore)

More broadly, this analysis showed that combinations of transmission options to the east and north of the East Anglia region were economically optimal, and that onshore overhead line options would be preferred to offshore HVDC solutions.

The CPRSS concluded, taking all social-economic, environment, technical and cost factors, into account, that the preferred solution was a combination of offshore and onshore connections with three distinct elements: an offshore reinforcement between the south coast and East Anglia (SCD1 and referred to as Sea Link); onshore reinforcement between Tilbury and Grain (TENC); and onshore reinforcement between Norwich and Tilbury (AENC/ATNC) via Bramford substation and a new East Anglia Connection Node substation.

AENC, ATNC and SCD1 were given proceed signals in NOA 2021/22, and the July 2022 NOA Refresh also identified these reinforcements as 'HND essential' options, meaning that NESO considers them to be essential to meet the UK Government's 2030 offshore wind targets. TENC does not have a proceed signal nor is it considered as required currently in the NOA Refresh and is therefore not being taken forward at this time.

The analysis for the NOA and HND provided a solid foundation for identifying strategic options that are most viable and should be taken through further analysis.

2025 Backcheck and review of strategic options

A development since 2024 is the increasing constraint on routeing new offshore cable connections into the Tilbury substation. This is due to a combination of new and approved developments (e.g. Tilbury Freeport), pending planning applications (e.g. Tilbury Port expansion), and potential environmental designations (such as proposed SSSI status). The potential development of Tilbury North substation offered the potential for a more viable alternative.

Across all environmental, socio-economic, and technical domains, the review found no material changes that would alter the strategic conclusions reached in 2024. Updates to flood mapping, legislative changes (e.g. strengthened AONB (now called 'National Landscapes') duties), andreviews of new developments and infrastructure have been considered, but none were found to significantly alter the strategic viability of the assessed options.

The technical scope remains unchanged, with no new technologies identified and cost assessments continuing to align with the RIIO-T2 price control framework (2021–2026).

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, the conclusion following the review and update is that the combination of **EAN 4 OHL Norwich Main to Bramford** and **EAS 2 OHL Bramford via a new substation to Tilbury** remains the preferred strategic options for the Norwich to Tilbury project and will now be taken forward to the next stage of development.

1. Introduction

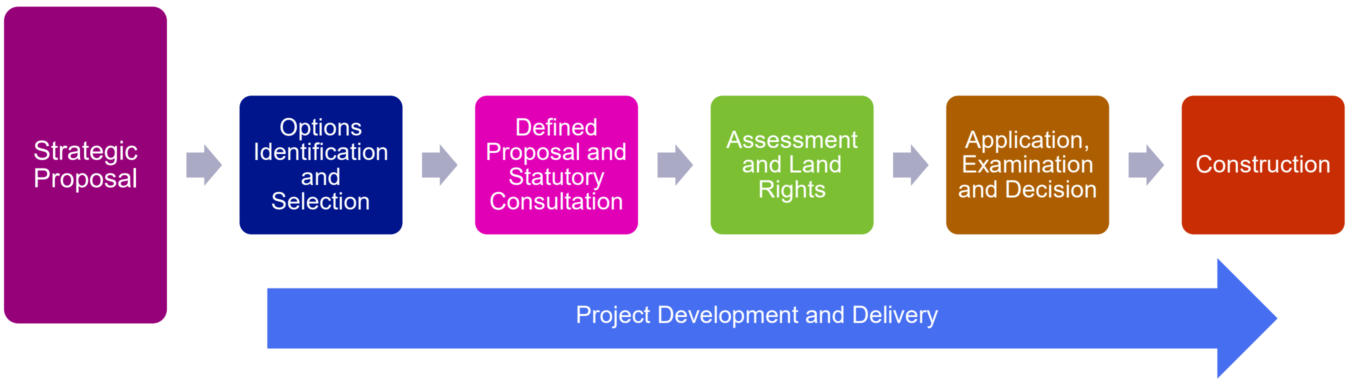
1.1.1 This version of the Strategic Options Backcheck and Review has been prepared by National Grid Electricity Transmission plc (NGET) as part of the ongoing strategic options assessment and decision-making process involved in promoting new transmission projects. It records how we have had regard to 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 backcheck and review of the strategic options considered for the Norwich to Tilbury project in East Anglia against the need case. The project is described in greater detail within the 2024 Strategic Options Backcheck and Review, which can be found in Appendix B of this report.

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. This backcheck report describes any changes since the 2024 Strategic Options Backcheck and Review and any impacts these changes may have on the strategic options.

1.1.4 The identification of a strategic proposal establishes the scope of the project which commences with Options Identification and Selection. This document forms part of the 'Options identification and selection' stage and 'Defined proposal and statutory consultation' stage.

Figure 1.1 Approach to consenting process



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

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. In 2024, the UK Government also committed to achieving a clean electricity system by 2030. 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 Government has set out how it plans to deliver on these commitments within multiple plans including:

- November 2020: Prime Minister's Ten Point Plan for a Green Industrial Revolution[2].
- December 2020: Energy White Paper: Powering our Net Zero Future[3].
- October 2021: Net Zero Strategy: Build Back Greener[4].
- April 2022: British Energy Security Strategy (BESS)[5]. This document is built on the Net Zero Strategy and was published in response to the Russian invasion of Ukraine and the 2022 energy price crisis.
- March 2023: Powering Up Britain[6] and Powering Up Britain: Energy Security Plan[7]. These documents provide an update of the strategy for secure, clean and affordable British energy for the long-term future.
- December 2024: Clean Power 2030 Action Plan: A new era of clean electricity[8]. This document provides the strategic initiative aimed at transitioning to cleaner energy sources and reducing carbon emissions and was issued following NESO's

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[2] The Ten Point Plan for a Green Industrial Revolution, HM Government, November 2020 https://assets.publishing.service.gov.uk/media/5fb5513de90e0720978b1a6f/10_POINT_PLAN_BOOKLET.pdf
[3] Energy White Paper: Powering our Net Zero Future, HM Government, December 2020 https://assets.publishing.service.gov.uk/media/5fdc61e2d3bf7f3a3bdc8cbf/201216_BEIS_EWP_Command_Paper_Accessible.pdf
[4] Net Zero Strategy: Build Back Greener, HM Government, October 2021 https://assets.publishing.service.gov.uk/media/6194dfa4d3bf7f0555071b1b/net-zero-strategy-beis.pdf
[5] British Energy Security Strategy, HM Government, April 2022 https://assets.publishing.service.gov.uk/media/626112c0e90e07168e3fdba3/british-energy-security-strategy-web-accessible.pdf
[6] Powering up Britain, HM Government, March 2023 https://assets.publishing.service.gov.uk/media/642468ff2fa8480013ec0f39/powering-up-britain-joint-overview.pdf
[7] Powering up Britain: Energy Security Plan, HM Government, March 2023 https://assets.publishing.service.gov.uk/media/642708eafbe620000f17daa2/powering-up-britain-energy-security-plan.pdf
[8] Clean Power 2030 Action Plan: A new era of clean electricity, UK Government, December 2024 https://assets.publishing.service.gov.uk/media/677bc80399c93b7286a396d6/clean-power-2030-action-plan-main-report.pdf

Clean Power 2030: Advice on achieving clean power for Great Britain by 2030[9] publication where the Norwich to Tilbury projects (AENC and ATNC) are highlighted as two of the *"three projects identified as critical to delivering a network which supports the clean power pathways, but at present have delivery dates after 2030".*

2.1.2 Key ambitions contained within these plans to achieve net zero include:

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

2.2 The transmission system

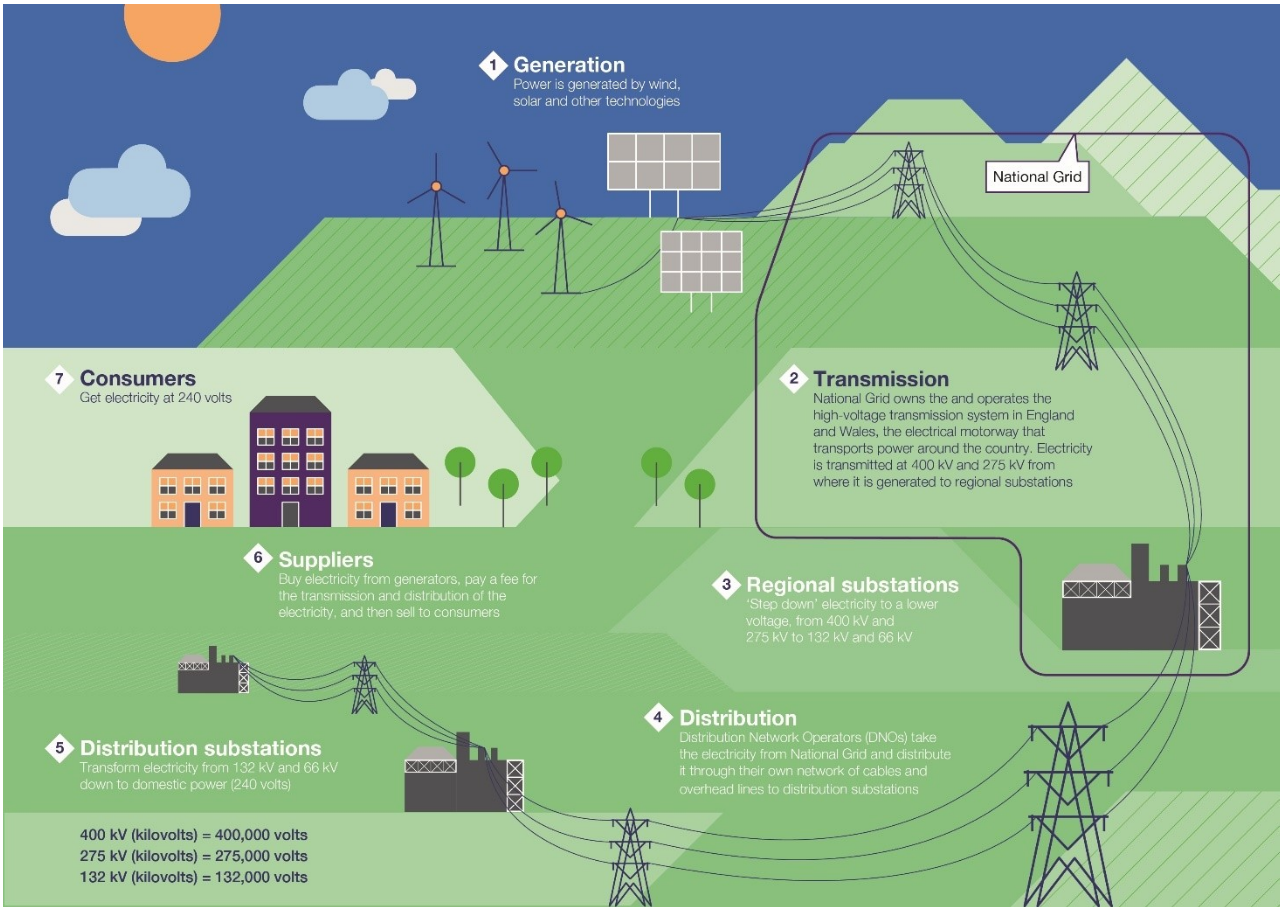
2.2.1 The electricity transmission system is a means of transmitting electricity around the country from where it is generated to where it is needed. The existing transmission system in Great Britain operates at voltage levels of 400 kV and 275 kV and transports bulk supplies of electricity from large generating stations to demand centres. These systems are typically the responsibility of the Transmission Owners (TOs). Lower voltage distribution systems operate at 132 kV and below in England and Wales and are mainly used to transport electricity from substations (interface points with the transmission system) to the majority of end customers. These systems are typically the responsibility of the Distribution Network Operator (DNO). The electricity system is illustrated in Figure 2.1.

What is demand?

Demand is electricity used by domestic and non-domestic consumers, for example the electricity used within the home or by businesses.

[9] Clean Power 2030: Advice on achieving clean power for Great Britain by 2030 https://www.neso.energy/document/346651/download

Figure 2.1 The electricity system from generator to consumer



2.2.2 There are three Transmission Owners (TOs) for Great Britain's network. NGET is the TO for the transmission network in England and Wales. SP Energy Networks is the TO for Southern Scotland, and Scottish and Southern Electricity Networks (SSEN) is the TO for Northern Scotland and Scottish Islands Groups.

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

2.2.4 Substations provide points of connection to the transmission system for power generation stations, distribution networks, transmission connected demand customers (e.g., large industrial customers) and interconnectors. Circuits connect 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.

What are interconnectors?

Interconnectors are transmission links that connect the electricity networks in two countries to allow for the transfer of electricity across borders. Currently the Great Britain system has interconnectors with France, Netherlands, Belgium and other countries.

2.2.5 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 generation stations and interconnectors with other countries' transmission systems.

2.2.6 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 and sell it in the wholesale market. Suppliers purchase electricity in the wholesale market and supply to end customers.

2.2.7 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, Belgium, Denmark, the Netherlands and other countries are used to import electricity to and/or export electricity from Great Britain's transmission system.

2.3 National Grid's role

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

2.3.2 NGET's transmission system consists of approximately 7,200 km of overhead lines and 700 km of underground cabling, operating at voltage levels of 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 transmission substations forming a highly interconnected transmission system.

2.3.3 Transmission of electricity in Great Britain requires permission by a licence granted under Section 6(1)(b) of the Electricity Act 1989[10] (as amended) (the Electricity Act). NGET has been granted a transmission licence[11] (the Transmission Licence) and is therefore bound by legal obligations, which are primarily set out in the Electricity Act and the Transmission Licence.

2.3.4 NGET's legal obligations include duties under Section 9, Section 38 and Schedule 9 of the Electricity Act. NGET must develop and maintain an efficient, coordinated, and economical electricity transmission system while considering the preservation of natural beauty and important sites of architectural, historic, or archaeological interest. They should also mitigate any negative impacts on these features. In summary, NGET is required to:

- Develop and maintain an efficient electricity transmission system.
- Invest in upgrading infrastructure, such as overhead lines and substations, to connect more low-carbon power sources to meet future demand.
- Collaborate with NESO to facilitate the connection of large energy projects to the transmission network, ensuring electricity can reach homes and businesses.

2.3.5 For more details on these obligations, see Appendix B in the 2024 Strategic Options Backcheck and Review (Appendix B).

[10] Electricity Act 1989
https://www.legislation.gov.uk/ukpga/1989/29/contents
[11] Licences and licence conditions, Ofgem
https://www.ofgem.gov.uk/energy-policy-and-regulation/industry-licensing/licences-and-licence-conditions

2.3.6 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

2.3.7 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.

2.3.8 A more detailed consideration of NGET's legal duties is set out in Appendix A in the 2024 Strategic Options Backcheck and Review (Appendix B).

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 NESO 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, NESO 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 NESO. 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 NGET's requirement to reinforce the transmission system

2.5.1 NGET's duties are determined by the Electricity Act 1989 ('the Electricity Act') and 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.

2.5.2 As part of NGET's Transmission Licence requirements, the transmission infrastructure needs to be capable of providing and maintaining a minimum level of security and quality of supply and of transporting electricity from and to customers. NGET is required to ensure that the transmission system remains capable as customer requirements change.

2.5.3 Capacity refers to the theoretical maximum limit of a circuit, while capability denotes the practical limit imposed by physical and operational constraints. The capacity of the transmission system is determined by the physical ability of electrical circuits to carry power. Each circuit has a specific capacity, and the total capacity of the circuits within a region or across a boundary is the cumulative sum of the capacities of all individual circuits.

2.5.4 On the other hand, the capability of the transmission system represents the natural flow of energy that can occur within the network's infrastructure. Due to the inherent physical properties of the transmission system, this capability is often less than the theoretical capacity of the infrastructure. This distinction is crucial for understanding how effectively the transmission system can operate under real-world conditions.

2.5.5 The transmission system must accommodate changes in demand, generation, and interconnectors. Customers can apply to NESO for new or modified connections. Upon receiving applications, the relevant transmission owner uses the TEC Register to assess the generation group and determine if the transmission system can support the proposed changes. If capacity is available, NESO will extend a formal offer of connection.

2.5.6 Where power flows are constrained by the transmission system across a specific number of circuits, this is termed a ‘boundary’ by NESO. Such boundaries are used in the Electricity Ten Year Statement (ETYS) to identify constraints which may require changes to the transmission system in the next 10 years. Where the ‘boundary capacity’ is exceeded against the standards of the Security and Quality of Supply Standard (SQSS), NGET must resolve the capacity shortfall.

2.6 The role of the National Energy System Operator (NESO)

2.6.1 The National Energy System Operator (NESO) is the electricity system operator for Great Britain. NESO ensures electricity is always where it is needed, and the transmission network remains stable and secure in its operation.

2.6.2 As of 1 October 2024, NESO became a public body owned by the DESNZ. It was formerly part of National Grid PLC and called the Electricity System Operator (ESO).

2.6.3 NESO has been established to act as the independent organisation responsible for planning Great Britain’s energy system, looking after and operating the electricity and gas networks while also offering expert advice to the sector’s decision-makers.

2.6.4 Generators apply to NESO when they wish to connect to the network and NESO leads, working with the TOs, to consider how the network may need to evolve to deliver a cleaner greener future. NESO is currently reforming their connection processes to meet the increasing number of projects wanting to connect to the transmission system.

2.6.5 NESO, in undertaking this role, engages with NGET for England and Wales as well as the two TOs in Scotland, SSEN and SP Energy Networks.

2.6.6 NESO and its predecessor ESO have been or – in the case of NESO - are responsible for multiple roles across the electricity system, including:

- Electricity market balancing: NESO ensures that electricity demand and supply is balanced on a second-by-second basis and manages any shortfalls in boundary capacity.

What is a boundary?

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.

- Future Energy Scenarios: NESO undertakes an annual process to publish the Future Energy Scenarios[12] (FES) which takes energy industry views as part of a consultation process and develops a set of possible energy growth scenarios to 2050. In developing FES, NESO takes into consideration the latest pipeline of connections as detailed within the Transmission Entry Capacity (TEC) Register. TEC Register is essential for managing the UK's electricity transmission network, providing an overview of the capacity available for new connections. As customers apply to NESO for new or modified connections, the TEC Register helps assess the current and future capacity needs of the network planning: NESO annually publish the Electricity Ten Year Statement (ETYS)[13] setting out the network performance and requirements for all transmission in Great Britain over the next 10 years based on the data from the FES. ESO used the ETYS to publish annually the Network Options Assessment[14] (NOA), which considered the economic case for options to reinforce the transmission system and makes economic recommendations. The NOA included a Cost Benefit Analysis (CBA) process to determine when would be appropriate to take forward options proposed by TOs to increase network capacity. This considers the capital costs of the proposal, delivery timescales and constraint costs (as explained in Chapter 5) avoided by delivering the proposal. This establishes when a proposed reinforcement becomes the most economical way to deliver value to Great Britain's energy consumers.
- Network Planning Review (NPR): The Pathway to 2030 HND (Holistic Network Design) and the recommendations set out in the most recent NOA (Network Options Assessment) prepared by ESO were the first steps towards a more centralised, strategic network planning approach that is critical for delivering affordable, clean and secure power, with a view to achieving net zero.
- NESO is currently transitioning from the NOA to a more comprehensive approach, a Centralised Strategic Network Plan[15] (CSNP). The CSNP will aim to foster the holistic development of the NETS, marking a new era in our network planning
- Connections: NESO facilitates several roles on behalf of the electricity industry, including making formal offers to connection applicants to the electricity transmission system. NGET is obligated to provide the physical connections to the elements of the electricity transmission system that NGET owns.

[12] Future Energy Scenarios 2024: NESO Pathways to Net Zero https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[13] Electricity Ten Year Statement (ETYS) https://www.neso.energy/publications/electricity-ten-year-statement-etys
[14] Network Options Assessment 2021/22 Refresh, National Grid ESO, July 2022 https://www.neso.energy/document/262981/download
[15] Decision on the initial findings of our Electricity Transmission Network Planning Review, Ofgem https://www.ofgem.gov.uk/publications/decision-initial-findings-our-electricity-transmission-network-planning-review

2.6.7 The planning activities undertaken by NESO are currently being updated to support the delivery of the Government's net-zero commitment. In 2022, ESO published the HND setting out an integrated approach to transmission network design that supports the connection of 23 GW of offshore wind to Great Britain by 2030. The ESO is also undertaking the Offshore Co-ordination Project[16], 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.

2.6.8 Subsequent to the ESO reinforcements identified in HND and NOA refresh, Ofgem have published the Accelerated Strategic Transmission Investment (ASTI)[17] decision, which aims to facilitate achieving government targets by streamlining the regulatory approval and funding process for ASTI projects. Norwich to Tilbury is an ASTI project.

2.7 NGET's statutory duties

2.7.1 This chapter details the statutory duties most relevant to the development of new infrastructure. These duties are considered in NGET's approach to identifying options and the selection process. This is shown in NGET's review of potential strategic options and the application of the appraisal factors, as reported in Chapter 5 of this report.

2.7.2 For the purposes of this provision, National Grid is classified as a 'relevant authority' due to its status as a 'statutory undertaker,' which means that these duties apply to it.

2.7.3 The relevant statutory duties include:

- Electricity Act 1989
- National Parks and Access to the Countryside Act 1949
- Countryside and Rights of Way Act 2000
- Natural Environment and Rural Communities Act 2006
- Wildlife and Countryside Act 1981
- Planning (Listed Buildings and Conservation Areas) Act 1990

Electricity Act 1989

2.7.4 When developing new infrastructure, NGET is required to comply with the following duties.

2.7.5 Section 9(2) of the Electricity Act (General duties of licence holders) states:

[16] Offshore Coordination
https://www.neso.energy/about/our-projects/offshore-coordination
[17] Accelerated Strategic Transmission Investment (ASTI)
https://www.ofgem.gov.uk/decision/decision-accelerating-onshore-electricity-transmission-investment#:~:text=In%20August%202022%20we%20consulted%20on%20how%20Ofgem,a%20new%20Accelerated%20Strategic%20Transmission%20Investment%20%28ASTI%29%20framework.

"it shall be the duty of the holder of a licence authorising him to participate in the transmission of electricity: (a) to develop and maintain an efficient, co-ordinated and economical system of electricity transmission…;"

2.7.6 Section 38 and Schedule 9 of the Electricity Act state that:

"(1) In formulating any relevant proposals, a licence holder…

- (a) 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

- (b) 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."

National Parks and Access to the Countryside Act 1949

2.7.7 Section 11A (1A) of the National Parks and Access to the Countryside Act 1949 imposes a duty on certain bodies and persons in respect of National Parks. The duty provides as follows:

"(1A) In exercising or performing any functions in relation to, or so as to affect, land in any National Park in England, a relevant authority other than a devolved Welsh authority must seek to further the purposes specified in section 5(1) and if it appears that there is a conflict between those purposes, must attach greater weight to the purpose of conserving and enhancing the natural beauty, wildlife and cultural heritage of the area comprised in the National Park."

2.7.8 Section 5 sets out the statutory purposes of the National Park, as follows:

"(1) The provisions of this Part of this Act shall have effect for the purpose—

(a) of conserving and enhancing the natural beauty, wildlife and cultural heritage of the areas specified in the next following subsection; and

(b) of promoting opportunities for the understanding and enjoyment of the special qualities of those areas by the public."

Countryside and Rights of Way Act 2000

2.7.9 Section 85 of the Countryside and Rights of Way Act 2000 imposes a duty on public bodies in respect of areas of outstanding natural beauty. The duty provides as follows:

"(A1) In exercising or performing any functions in relation to, or so as to affect, land in an area of outstanding natural beauty in England, a relevant authority other than a devolved Welsh authority must seek to further the purpose of conserving and enhancing the natural beauty of the area of outstanding natural beauty."

Natural Environment and Rural Communities Act 2006

2.7.10 Section 40 of the Natural Environment and Rural Communities Act 2006 imposes a duty in respect of biodiversity. The duty provides as follows:

"(A1) For the purposes of this section "the general biodiversity objective" is the conservation and enhancement of biodiversity in England through the exercise of functions in relation to England.

(1) A public authority which has any functions exercisable in relation to England must from time to time consider what action the authority can properly take, consistently with the proper exercise of its functions, to further the general biodiversity objective."

Wildlife and Countryside Act 1981

2.7.11 Section 28G of the Wildlife and Countryside Act 1981 imposes a duty on 'statutory undertakers' in respect of sites of special scientific interest. The duty provides as follows:

"(1) An authority to which this section applies (referred to in this section and in sections 28H and 28I as "a section 28G authority") shall have the duty set out in subsection (2) in exercising its functions so far as their exercise is likely to affect the flora, fauna or geological or physiographical features by reason of which a site of special scientific interest is of special interest.

(2) The duty is to take reasonable steps, consistent with the proper exercise of the authority's functions, to further the conservation and enhancement of the flora, fauna or geological or physiographical features by reason of which the site is of special scientific interest."

Planning (Listed Buildings and Conservation Areas) Act 1990

2.7.12 Section 66 of the planning (Listed Buildings and Conservation Areas) Act 1990 imposes a duty on planning authorities in respect of listed buildings. The duty provides as follows:

"(1) In considering whether to grant planning permission for development which affects a listed building or its setting, the local planning authority or, as the case may be, the Secretary of State shall have special regard to the desirability of preserving the building or its setting or any features of special architectural or historic interest which it possesses."

2.7.13 Section 72 imposes a duty in relation to conservation area, as follows:

"(1) In the exercise, with respect to any buildings or other land in a conservation area, of any powers under any of the provisions mentioned in subsection (2), special attention shall be paid to the desirability of preserving or enhancing the character or appearance of that area."

"(2) The provisions referred to in subsection (1) are the planning Acts and Part I of the Historic Buildings and Ancient Monuments Act 1953 and sections 70 and 73 of the Leasehold Reform, Housing and Urban Development Act 1996"

2.8 National Policy Statements (NPSs)

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 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. The NPSs were designated in January 2024.

2.8.2 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 Backcheck and Review. An overview of main themes relevant to this backcheck and review is provided below with more detailed commentary within Appendix B in the 2024 Strategic Options Backcheck Report (Appendix B) to the Design Development Report published as part of the 2024 Statutory Consultation.

2.8.3 The Overarching NPS for Energy (NPS EN-1) sets out the Government's overarching policy about the development of NSIPs in the energy sector. It sets out the goal of decarbonising the energy network to achieve net zero whilst ensuring security of supply. It sets out how as the electricity system grows in scale, dispersion, variety, and complexity, work would be needed to protect against the risk of large-scale supply interruptions in the absence of sufficiently robust electricity networks. While existing transmission and distribution networks must adapt and evolve to cope with this reality, development of new transmission lines of 132 kV and above would be necessary to preserve and guarantee the robust and reliable operation of the whole electricity system. EN-1 recognises that to 'produce the energy required for the UK and ensure it can be transported to where it is needed, a significant amount of infrastructure is needed at both local and national scale. It refers to how the onshore transmission network would require substantial reinforcement in East Anglia to handle increased power flows from offshore wind generation (paragraph 3.3.68).

2.8.4 NPS EN-1 Section 4.2 sets out the Government's commitments to prioritise for low carbon infrastructure. Paragraph 4.2.1 states that *"Government has committed to fully decarbonise the power systems by 2035, subject to security of supply, to underpin its 2050 net zero ambitions."* Paragraph 4.2.4 states that the *"Government has therefore concluded that there is a critical national priority (CNP) for the provision of nationally significant low carbon infrastructure."* Paragraph 4.2.5 lists the types of infrastructure which are nationally significant low carbon infrastructure for the purposes of the CNP policy, and this includes electricity grid infrastructure in the scope of EN-5, including network reinforcement, upgrade works and associated infrastructure such as substations.

2.8.5 NPS EN-3 for Renewable Energy Infrastructure, also includes support for the onshore infrastructure required to deliver new offshore wind developments. Paragraphs 2.8.34 to 2.8.43 (inclusive) reiterate the position set out in EN-1 and EN-5 that a co-ordinated approach to onshore-offshore transmission is required. The NPS also includes references to CNP Infrastructure, and the application of the assessment principles outlined in Section 4 of EN-1. Applicants must show how any likely significant negative effects would be avoided, reduced, mitigated or compensated for, following the mitigation hierarchy.

2.8.6 NPS EN-5 (National Policy Statement for Electricity Networks Infrastructure) in conjunction with NPS EN-1 sets the policy context and provides the main guidance for the development and assessment of new network infrastructure. It outlines the Government's view that the development of overhead lines is not incompatible in principle with an applicants' statutory duty under Schedule 9 to the Electricity Act

1989 to have regard to visual and landscape amenity and to reasonably mitigate possible impacts. It sets out the government's position that overhead lines should be the strong starting presumption for electricity networks developments and that The Holford Rules (guidelines for the routing of new overhead lines) and the equivalent Horlock Rules for substation infrastructure, should be embodied in the applicants' proposals. The NPS goes on to recognise that this presumption is reversed (i.e assuming underground cable) when proposed developments will cross part of a nationally designated landscape (i.e. National Park, The Broads, or Areas of Outstanding Natural Beauty).

2.8.7 The NPS also sets out that the need to consider the case for undergrounding outside designated areas (2.9.23) and to consider, where there is the potential for significant adverse landscape and visual impacts (2.9.14), the need to have given due consideration to feasible alternatives to the overhead line. This could include, where appropriate, re-routing, underground or subsea cables, and the feasibility e.g. in cost, engineering or environmental terms of these but with decision making taking into account the costs and benefits of the alternatives.

2025 Revisions to National Policy Statements

2.8.8 In April 2025, the government launched a consultation on proposed changes to EN-1, EN-3 and EN-5.

2.8.9 The proposed changes presented in the draft EN-1, EN-3 and EN-5 would not change the appraisal outcomes.

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 and 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 NGET 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, NGET must resolve the capacity shortfall under the terms of its Transmission Licence. The standards against which NGET 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[18] (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 NESO 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, NESO will coordinate the process known as CION /HND to determine the preferred connection option.

3.2.4 NESO ensures the relevant onshore 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 NGET, 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 NGET assesses the adequacy of its transmission system in accordance with the method defined in the NETS Security and Quality of Supply Standard (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.

[18] National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) https://www.neso.energy/document/358751/download

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 Southeast 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 212km 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 2030/31 is anticipated to be approximately 1,281 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 132kV connected gas fired power stations.

3.3.5 With the recent commencement of public consultation on the Western Marsh to East Lincolnshire project, the generation at Spalding North would no longer be impactful on the East Anglia boundary and therefore no longer considered to be impacting the East Anglia region need case.

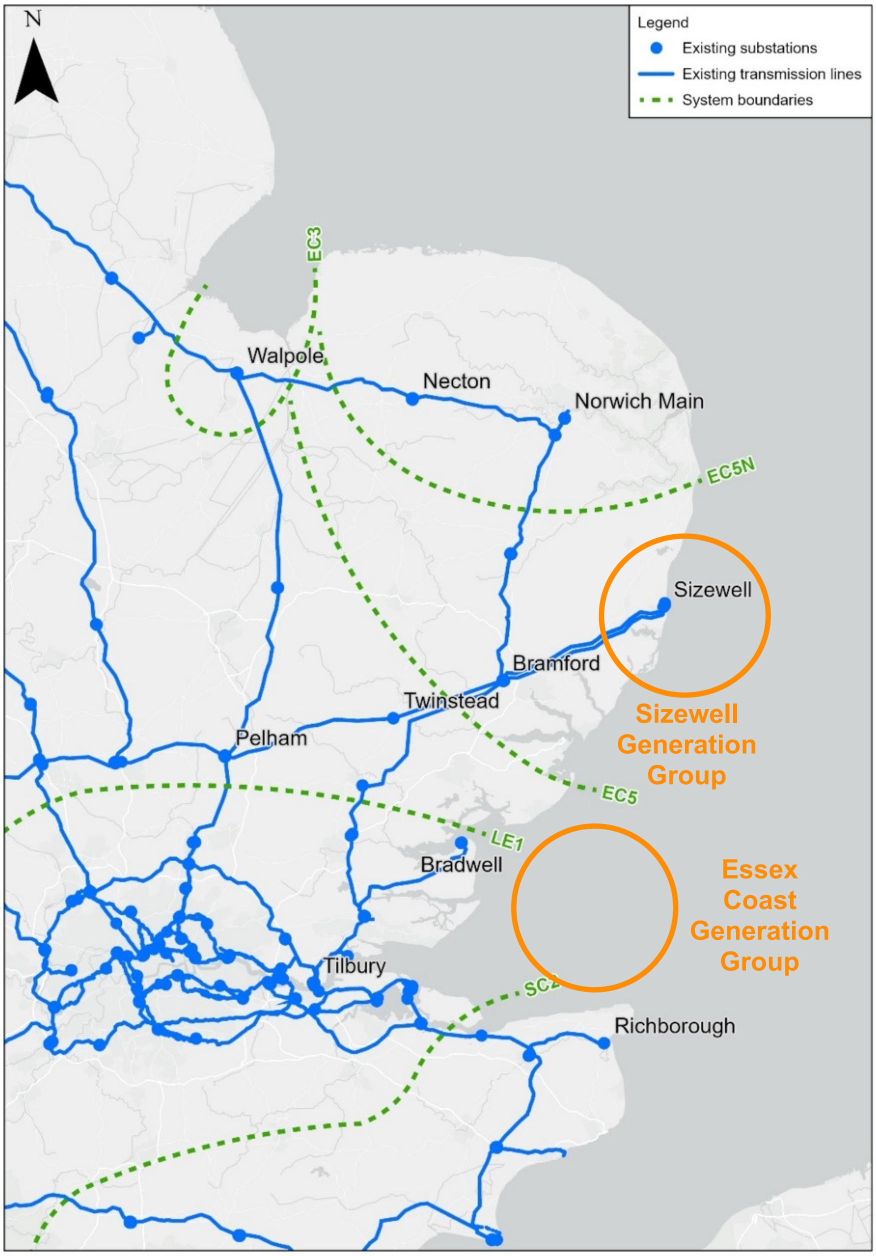
3.3.6 This generation capacity, excluding Spalding North, has recently been added to by several offshore windfarms with the existing generation totalling 6,552.4 MW of installed capacity. This is expected to grow substantially in coming years, as discussed further below.

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

3.3.8 The SC2 area around Kent is formed of a set of circuits linking from Kemsley in the North of Kent to Lovedean in Hampshire, with existing generation connections of 5693.8.8MW and peak demand in the area anticipated to be 1,556 MW by 2030/31 (total demand at substations of Canterbury North, Sellidnge, Ninfield and Bolnley).

3.3.9 The existing transmission system in East Anglia and Southeast is shown in Figure 3.1 below, with the inclusion of the Bramford to Twinstead connection for which development consent was granted in September 2024.

Figure 3.1 East Anglia and Southeast region transmission system and system boundaries



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

3.4.1 As discussed in the previous chapter, 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 50GW of offshore wind by 2030s as a key part of a strategy for secure, clean and affordable British energy for the long term.

3.4.2 NGET 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 Southeast is required for the following reason.

3.4.3 Without reinforcement the capacity of the East Anglia and Southeast 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 NGET assesses these shortfalls are set out in the SQSS. This is described in more detail later in this chapter.

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 677 MW in 2023/24 to 1,281 MW in 2030/31.

3.5.2 The demand in the North of East Anglia (Walpole and Norwich) is expected to increase from 213 MW in 2023/24 to 605 MW in 2030/31.

Table 3.1 2022 WK24 Forecast Demand for the East Anglia Region

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
East Anglia Demand (MW)	677	713	776	851	955	1,055	1,159	1,281
North East Anglia Demand (MW)	213	235	274	323	390	455	524	605

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 26,919.9 MW of new generation (total generation of 33,472.3 MW minus Existing Generation of 6,552.4 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 NESO TEC registers as of 11/06/25
(#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	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	Pivoted Power (Walpole)	Walpole 400kV	Energy Storage	57.0 MW	0.83	47.3 MW	*		
Existing	Damoson Green (Bramford)	Bramford 400kV	Energy Storage	57.0 MW	0.83	47.3 MW			
Existing	East Anglia One	Bramford 400kV	Wind	680.0 MW	0.7	476.0 MW			
2022	Brook Farm BESS	Bramford 400kV	Energy Storage	49.9 MW	0.83	41.4 MW			
2024	Yare Power	Norwich 400kV	Energy Storage/PV Array	49.5 MW	0.83	41.1 MW	*		
2025	Walpole Green Ltd	Walpole 400kV	Energy Storage	57.0 MW	0.83	47.3 MW	*		
2025	Pivoted Power (Norwich)	Norwich 400kV	Energy Storage	57.0 MW	0.83	47.3 MW	*		
2024	LionLink (EuroLink)	Friston	Interconnector	1,600.0 MW	1	1,600.0 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 Three stg1	Bramford 400kV	Wind	1,200.0 MW	0.7	840.0 MW			
2026	Bramford Green Stg 1	Bramford 400kV	Energy Storage	57.0 MW	0.83	47.3 MW			
2027	ENSO Green Holdings	Walpole 400kV	Energy Storage	100.0 MW	0.83	83.0 MW	*		
2028	East Anglia Two stg 1	Lieston 400kV	Wind	860.0 MW	0.7	602.0 MW			#
2028	East Anglia One North	Lieston 400kV	Wind	860.0 MW	0.7	602.0 MW			#
2028	Vanguard East 1	Necton 400kV	Wind	400.0 MW	0.7	280.0 MW	*		
2028	East Anglia Three stg 2	Bramford 400kV	Wind	100.0 MW	0.7	70.0 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	920.0 MW	0.7	644.0 MW	*		
2029	Norfolk Boreas (stage 1)	Necton 400kV	Wind	400.0 MW	0.7	280.0 MW	*		
2029	Lapwing Fen II	Walpole 400kV	Energy Storage	249.6 MW	0.83	207.2 MW			
2029	Bramford BESS	Bramford 400kV	Energy Storage	400.0 MW	0.83	332.0 MW	*		
2030	Scira-Dudgeon Extension stg1	Norwich 400kV	Wind	719.0 MW	0.7	503.3 MW	*		
2030	East Anglia Two stg 2	Lieston 400kV	Wind	20.0 MW	0.7	14.0 MW	*		
2030	Norfolk Boreas (stage 2)	Necton 400kV	Wind	920.0 MW	0.7	644.0 MW	*		
2030	Alcemi Bramford Battery	Bramford 400kV	Energy Storage	500.0 MW	0.83	415.0 MW			
2031	High Grove Solar	Necton 400kV	Energy Storage/PV Array	720.0 MW	0.83	597.6 MW	*		
2031	Evolution Power Norfolk	Walpole 400kV	Energy Storage/PV Array	860.0 MW	0.83	713.8 MW	*		
2031	Scira-Dudgeon Extension stg2	Norwich 400kV	wind	231.0 MW	0.7	161.7 MW			
2031	Norwich Green Energy Centre	Norwich 400kV	Energy Storage	400.0 MW	0.83	332.0 MW	*		
2031	Norwich 100MW BESS	Norwich 400kV	Energy Storage	100.0 MW	0.83	83.0 MW	*		
2032	GF Norwich BESS	Norwich 400kV	Energy Storage	400.0 MW	0.83	332.0 MW	*		
2032	Bramford 2 GEC (Ethos Green)	Bramford 400kV	Demand/Energy Storage/PV	57.0 MW	0.83	47.3 MW	*		
2032	Norwich Main BESS - Long Stratton Stg1	North Anglia 400kV	Energy Storage	249.9 MW	0.83	207.4 MW	*		
2032	Necton Greener Grid Park	Necton 400kV	Energy Storage/Reactive Comp	78.0 MW	0.83	64.7 MW	*		
2033	Walpole flexible Generation	Walpole 400kV	CCGT/Energy Storage	2,000.0 MW	0.83	1,660.0 MW	*		
2033	Bramford GEC (Ethos Green)	Bramford 400kV	Demand/Energy Storage/PV	650.0 MW	0.83	539.5 MW	*		
2033	ER BRF 2 Energy	Bramford 400kV	Energy Storage/PV Array	249.0 MW	0.83	206.7 MW	*		
2033	Bradeham-Thetford (Necton) GEC (Ethos Green)	Necton 400kV	Demand/Energy Storage/PV	850.0 MW	0.83	705.5 MW	*		
2033	Norwich 2 EDF	Norwich 400kV	PV Array/Wind	28.0 MW	0.7	19.6 MW	*		
2033	Intwood Farm BESS	Norwich 400kV	Energy Storage	240.0 MW	0.83	199.2 MW	*		
20134	Norwich Main BESS - Long Stratton Stg2	North Anglia 400kV	Energy Storage	700.0 MW	0.83	581.0 MW	*		
2034	Scira-Dudgeon Extension stg3	Norwich 400kV	wind	400.0 MW	0.7	280.0 MW	*		
2034	Wymondham Road Farm	Norwich 400kV	Energy Storage	228.0 MW	0.83	189.2 MW	*		
2034	Necton High Impact Energy Hub	Necton 400kV	Energy Storage/PV Array/Onshore	1,000.0 MW	0.7	700.0 MW	*		
2034	Zenobe Necton BESS	Necton 400kV	Energy Storage	300.0 MW	0.83	249.0 MW	*		
2035	Sizewell C Stage 1	Sizewell 400kV	Nuclear	1,670.0 MW	0.85	1,419.5 MW			#
2036	Sizewell C Stage 2	Sizewell 400kV	Nuclear	1,670.0 MW	0.85	1,419.5 MW			#

Table 3.2 cont. Planned Generation for East Anglia

	Total Installed Capacity (MW)		Total Scaled Generation Capacity (MW)
Total Existing Generation (MW)	6,552.4 MW		5,042.3 MW
Total Generation Sizewell gneration group # (MW)	8,738.0 MW		7,282.1 MW
Total Generation Impacting EC5N* (MW)	21,404.9 MW		16,378.7 MW
Total Genration Existing and Contracted with No Fossil Fuel Contribution $ (MW)	31,541.8 MW		24,513.2 MW
Total Generation Existing and Contracted	33,472.3 MW		26,115.5 MW
Forecast ACS Peak Demand 2030/31			1,280.8 MW
Forecast ACS Peak Demand 2030/31 Impacting EC5N*			604.7 MW
Existing Planned Transfer at ACS Peak with All Generation (Existing Scaled Generation - Existing Demand)			4,365.0 MW
Transfer at ACS Peak with All Generation Sizewll Group (Total Scaled Generation# - No Demand in the group)			7,282.1 MW
Minimum Planned Transfer EC5 at ACS Peak with All Generation EC5N (Total Scaled Generation ($ excl fossil fuel) - Peak Demand)			14,171.7 MW
Maximum Transfer at ACS Peak with All Generation Impacting EC5N (Total Scaled Generation* - Peak Demand*)			15,774.0 MW
Minimum Planned Transfer EC5 at ACS Peak with All Generation (Total Scled Generation ($ excl fossil fuel) - Peak Demand)			23,232.4 MW
Maximum Planned Transfer EC5 at ACS Peak with All Generation (Total Scaled Generation - Peak Demand)			24,834.7 MW

3.6 Planned transfers

3.6.1 To assess SQSS compliance, NGET 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 NGET 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 gas turbine (CCGT and AGT) plant, energy storage and a small amount of biomass.

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 26,115.5 MW as compared to a total of 33,472.3 MW of installed generation capacity. The demand in the region at the time of system peak will be 1,280.8 MW.

3.6.11 This results in a forecast maximum Planned Transfer in 2031 of 24,834.7 MW export (26,115.5 MW minus 1,280.8 MW).

3.6.12 The minimum forecast planned transfer with no contribution from fossil fuels in 2031 would be 23,232.4 MW export (24,513.2 MW minus 1,280.8 MW).

3.6.13 Both the maximum and minimum forecast planned transfers are significant increases on the existing Planned Transfer export condition of 4,365.0 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 Southeast 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)
- 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 Walpole 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. This table shows capacity across the EC5 boundary including the completion of the Bramford to Twinstead project.

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

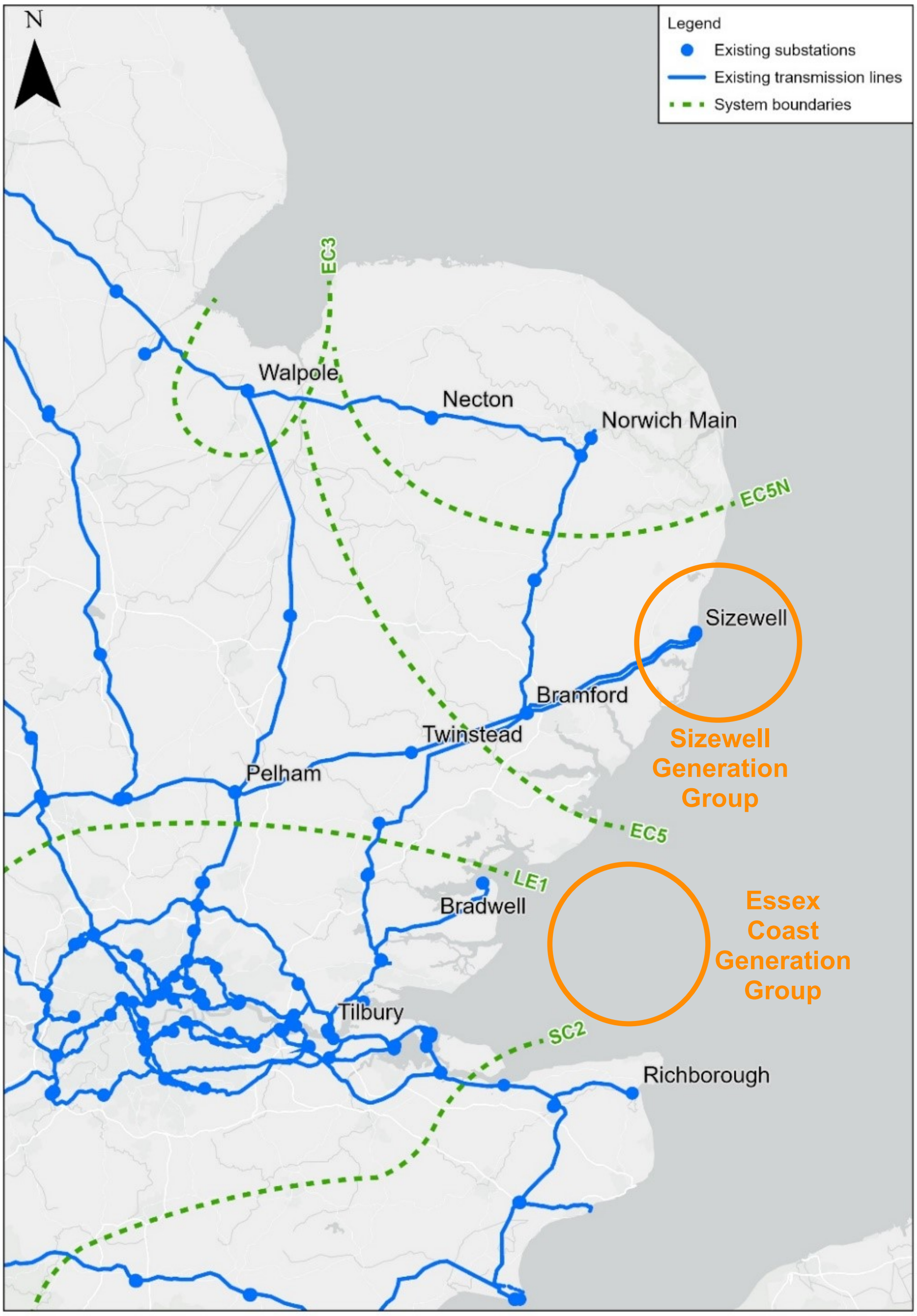


Table 3.3 Planned Transfer requirements

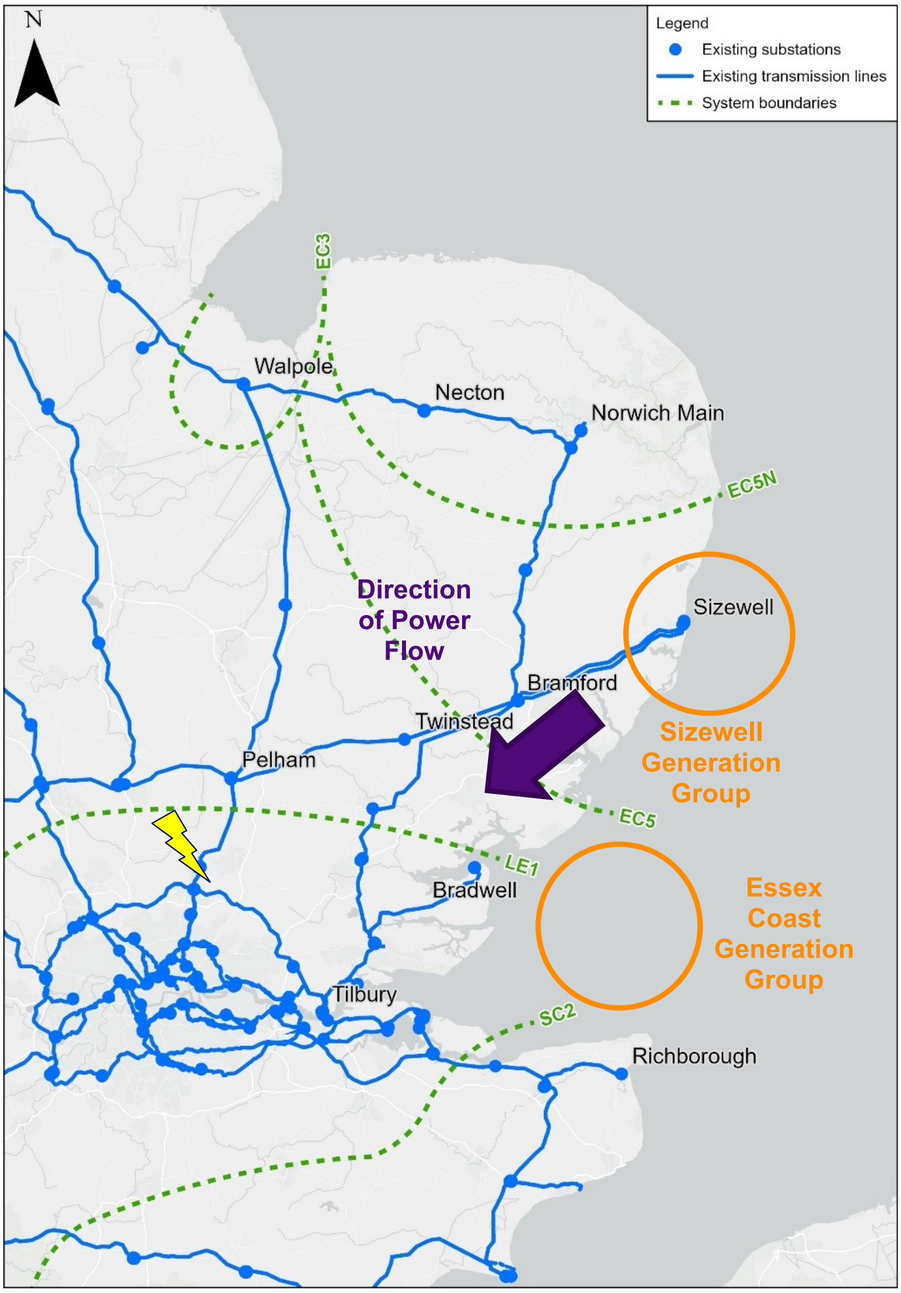
	Planned Transfer	Post Fault Capability by 2031	Planned Transfer Boundary Deficit
EC5N (Maximum)	15,774.0 MW	6,652 MW	**-9,122 MW**
EC5 (Maximum)	24,834.7 MW	13,552 MW	**-11,531 MW**
EC5N (Minimum)	14,171.7 MW	6,652 MW	**-7,520 MW**
EC5 (Minimum)	23,232.4 MW	13,552 MW	**-9,928 MW**

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 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 9,928 MW to circa 11,531 MW across and out of the East Anglia region. With the SQSS requiring us to design the network to accommodate the 9,928 MW lower range.

LE1 Boundary Fault and Impact

Figure 3.3 LE1 Boundary Fault and Impact



3.7.12 The region south of the EC5 boundary is the proposed connection location of the North Falls 1000 MW, Five Estuaries 1080 MW wind farms and Tarchon 1,400 MW interconnector.

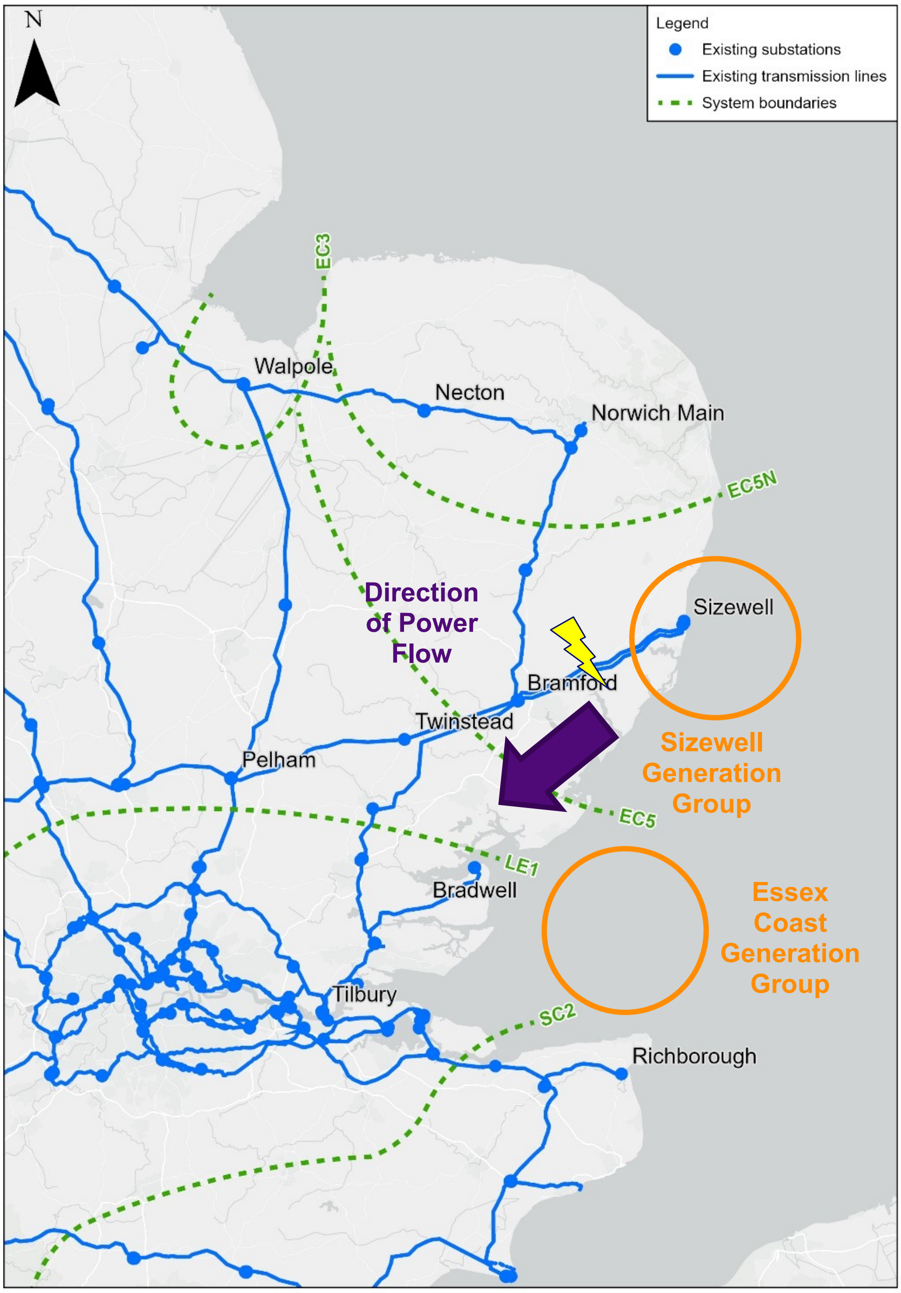
3.7.13 For the LE1 boundary the worst-case fault is for the Pelham – Rye House double circuit as shown in Figure 3.3. During this fault the East Anglia generation will naturally seek to flow down the Bramford – Braintree – Rayleigh circuits causing them to overload above their maximum potential capability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

3.7.14 With a requirement to provide additional 2,856 MW [(1000 MW + 1080 MW) x 0.7 + 1,400 MW] for the connection of North Falls, Five Estuaries and Tarchon as described as the Essex Coast Generation Group below increasing the deficit to -7,476 MW.

3.7.15 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

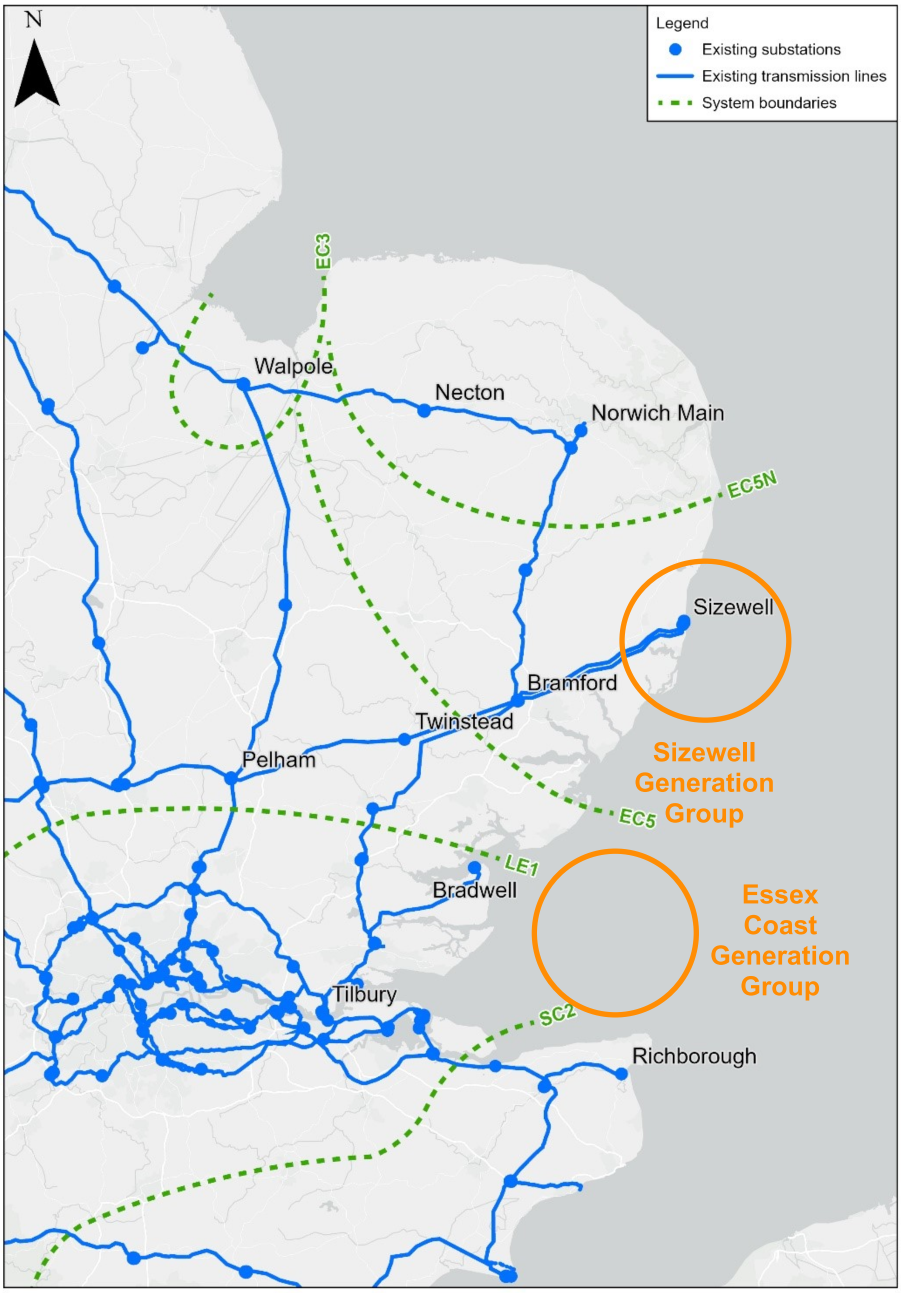
Figure 3.4 Sizewell Generation Groups fault and impact



3.7.16 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. This leaves the remaining circuit with a maximum potential capability of 6,930 MW and generation transfer of 7,282.1 MW leaving a deficit of more than -352.1 MW. This requires the Sizewell generation group to be reinforced for this condition.

Essex Coast Generation Group

Figure 3.5 Essex Coast Generation Need



3.7.17 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 (1,400 MW By 2030)
- North Falls offshore Windfarm (1,000 MW by 2030)
- Five Estuaries Offshore Windfarm (1,080 MW by 2030)

3.7.18 These connections are proposed to be made to the network at a location which can accommodate the combined 3,480 MW of total generation. This requires a minimum of 3 transmission circuits to connect the generation to meet the requirements of the NETS SQSS.

SC2 Boundary

Table 3.4 - Planned Generation and Planned Transfer for Boundary SC2 (Kent Area)
Generation Data from the NESO TEC registers as of 11/06/25

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	1,988.0 MW	1	1,988.0 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	Richborough 1	Richborough	Energy Storage	100.0 MW	0.83	83.0 MW
Existing	Richborough 2	Richborough	Energy Storage	100.0 MW	0.83	83.0 MW
Existing	Contego Battery Storage Project	Bolney	Energy Storage	35.8 MW	0.83	29.7 MW
Existing	Shoreham VPI Power	Bolney	CCGT	460.0 MW	0.83	381.8 MW
Existing	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	0.83	41.4 MW
2028	Bolnley Green	Bolney	Energy Storage	57.0 MW	0.83	47.3 MW
2025	Sheaf Energy Ltd	Richborough	Energy Storage	249.0 MW	0.83	206.7 MW
2025	Harrington Franklin Limited	Richborough	Energy Storage	49.9 MW	0.83	41.4 MW
2026	ENSO Green Holdings ltd	Canterbury North	Energy Storage	57.0 MW	0.83	47.3 MW
2027	Pivoted Power Bolney	Bolney	Energy Storage	49.9 MW	0.83	41.4 MW
2029	Blue Plannet Solar	Dungeness	PV Solar	500.0 MW	0.7	350.0 MW
2033	Dungeness Energy Park	Dungeness	Energy Storage/PV Solar	500.0 MW	0.7	350.0 MW
2030	Canterbury North 10 Renewables	East kent B	Energy Storage/PV array	1,000.0 MW	0.83	830.0 MW
2031	Kulizumboo Interconnector	Canterbury North	Interconnector	700.0 MW	1	700.0 MW
2031	Ninfield Greener Grid Park	Ninfield	Energy Storage	49.9 MW	0.83	41.4 MW
2031	Newchurch SSE Utility Solutions ltd	Newchurch	Energy Storage/PV Array	400.0 MW	0.83	332.0 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	0.83	207.5 MW
2033	Sellidge West	East Kent A	Energy Storage/PV array	1,000.0 MW	0.83	830.0 MW
2036	Project Invicta	East Kent B	Energy Storage/PV array	340.0 MW	0.83	282.2 MW
2036	GF Sellindge BESS	East Kent A	Energy Storage	300.0 MW	0.83	249.0 MW
2036	Project Cobalt	East Kent B	Interconnector	1,000.0 MW	1	1,000.0 MW
2036	Woodlands Farm BESS	Canterbury North	Energy Storage System	227.5 MW	0.83	188.8 MW
2037	Lightsource Newchurch	East Kent A	Energy Storage/PV array	240.0 MW	0.83	199.2 MW
2037	Dungeness Energy Park	East Kent A	Energy Storage/PV array	500.0 MW	0.83	415.0 MW
2037	Farmead and Yewtree Farm	East Kent A	Energy Storage	240.0 MW	0.83	199.2 MW
2037	Newchurch High Impact Energy	Newchurch	Energy Storage/PV/Onshore	1,000.0 MW	0.83	830.0 MW
2037	Bolnley Farm stg1	Bolney	Energy Storage/PV array	200.0 MW	0.83	166.0 MW
2037	Bolnley Farm Stg2	Bolney	Energy Storage/PV array	700.0 MW	0.83	581.0 MW
2037	Bolnley BESS	Bolney	Energy Storage	57.0 MW	0.83	47.3 MW
2037	Dragon Green BESS	Bolney	Energy Storage	300.0 MW	0.83	249.0 MW
2037	Kingsfold	Bolney	Energy Storage/PV array	49.9 MW	0.83	41.4 MW
2037	Lanehurst Farm BESS	Bolney	Energy Storage	225.0 MW	0.83	186.8 MW
2037	Ninfield Greener Grid Park stg2	Ninfield	Energy Storage	400.1 MW	0.83	332.1 MW
2037	Catsfeild	Ninfield	Energy Storage	240.0 MW	0.83	199.2 MW
2037	TH Ninfield	Ninfield	Energy Storage	200.0 MW	0.83	166.0 MW
2037	Henley Downs Farm BESS	Ninfield	Energy Storage	240.0 MW	0.83	199.2 MW
2037	Ninfield BESS	Ninfield	Energy Storage	225.0 MW	0.83	186.8 MW
2037	Partridge Farm BESS	Sellindge	Energy Storage	500.0 MW	0.83	415.0 MW
Total Existing Generation (MW)				**5,693.8 MW**		**5,279.8 MW**
Total Generation Impacting SC2 (MW)				**18,390.9 MW**		**15,899.4 MW**
Forecast SC2 ACS Peak Demand 2030/31						**1,556.1 MW**
Existing Planned Transfer at ACS Peak with All Generation (Existing Generation - Existing Demand)						**4,068.3 MW**
SC2 Transfer at ACS Peak 2031 all generation						**14,343.3 MW**

3.7.19 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 5873 MW with the capability limited by thermal and voltage stability issues. The existing planned transfer from the SC2 boundary is 4,068.3 MW, with +1804.7MW 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 NESO TEC registers as of 11/06/25						
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	1,988.0 MW	1	1,988.0 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	Richborough 1	Richborough	Energy Storage	100.0 MW	0.83	83.0 MW
Existing	Richborough 2	Richborough	Energy Storage	100.0 MW	0.83	83.0 MW
Existing	Contego Battery Storage Project	Bolney	Energy Storage	35.8 MW	0.83	29.7 MW
Existing	Shoreham VPI Power	Bolney	CCGT	460.0 MW	0.83	381.8 MW
Existing	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	0.83	41.4 MW
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2025	Sheaf Energy Ltd	Richborough	Energy Storage	249.0 MW	0.83	206.7 MW
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2027	Pivoted Power Bolney	Bolney	Energy Storage	49.9 MW	0.83	41.4 MW
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2033	Dungeness Energy Park	Dungeness	Energy Storage/PV Solar	500.0 MW	0.7	350.0 MW
2030	Canterbury North 10 Renewables	East kent B	Energy Storage/PV array	1,000.0 MW	0.83	830.0 MW
2031	Kulizumboo Interconnector	Canterbury North	Interconnector	700.0 MW	1	700.0 MW
2031	Ninfield Greener Grid Park	Ninfield	Energy Storage	49.9 MW	0.83	41.4 MW
2031	Newchurch SSE Utility Solutions ltd	Newchurch	Energy Storage/PV Array	400.0 MW	0.83	332.0 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	0.83	207.5 MW
2033	Sellidge West	East Kent A	Energy Storage/PV array	1,000.0 MW	0.83	830.0 MW
2036	Project Invicta	East Kent B	Energy Storage/PV array	340.0 MW	0.83	282.2 MW
2036	GF Sellindge BESS	East Kent A	Energy Storage	300.0 MW	0.83	249.0 MW
2036	Project Cobalt	East Kent B	Interconnector	1,000.0 MW	1	1,000.0 MW
2036	Woodlands Farm BESS	Canterbury North	Energy Storage System	227.5 MW	0.83	188.8 MW
2037	Lightsource Newchurch	East Kent A	Energy Storage/PV array	240.0 MW	0.83	199.2 MW
2037	Dungeness Energy Park	East Kent A	Energy Storage/PV array	500.0 MW	0.83	415.0 MW
2037	Farmead and Yewtree Farm	East Kent A	Energy Storage	240.0 MW	0.83	199.2 MW
2037	Newchurch High Impact Energy	Newchurch	Energy Storage/PV/Onshore	1,000.0 MW	0.83	830.0 MW
2037	Bolnley Farm stg1	Bolney	Energy Storage/PV array	200.0 MW	0.83	166.0 MW
2037	Bolnley Farm Stg2	Bolney	Energy Storage/PV array	700.0 MW	0.83	581.0 MW
2037	Bolnley BESS	Bolney	Energy Storage	57.0 MW	0.83	47.3 MW
2037	Dragon Green BESS	Bolney	Energy Storage	300.0 MW	0.83	249.0 MW
2037	Kingsfold	Bolney	Energy Storage/PV array	49.9 MW	0.83	41.4 MW
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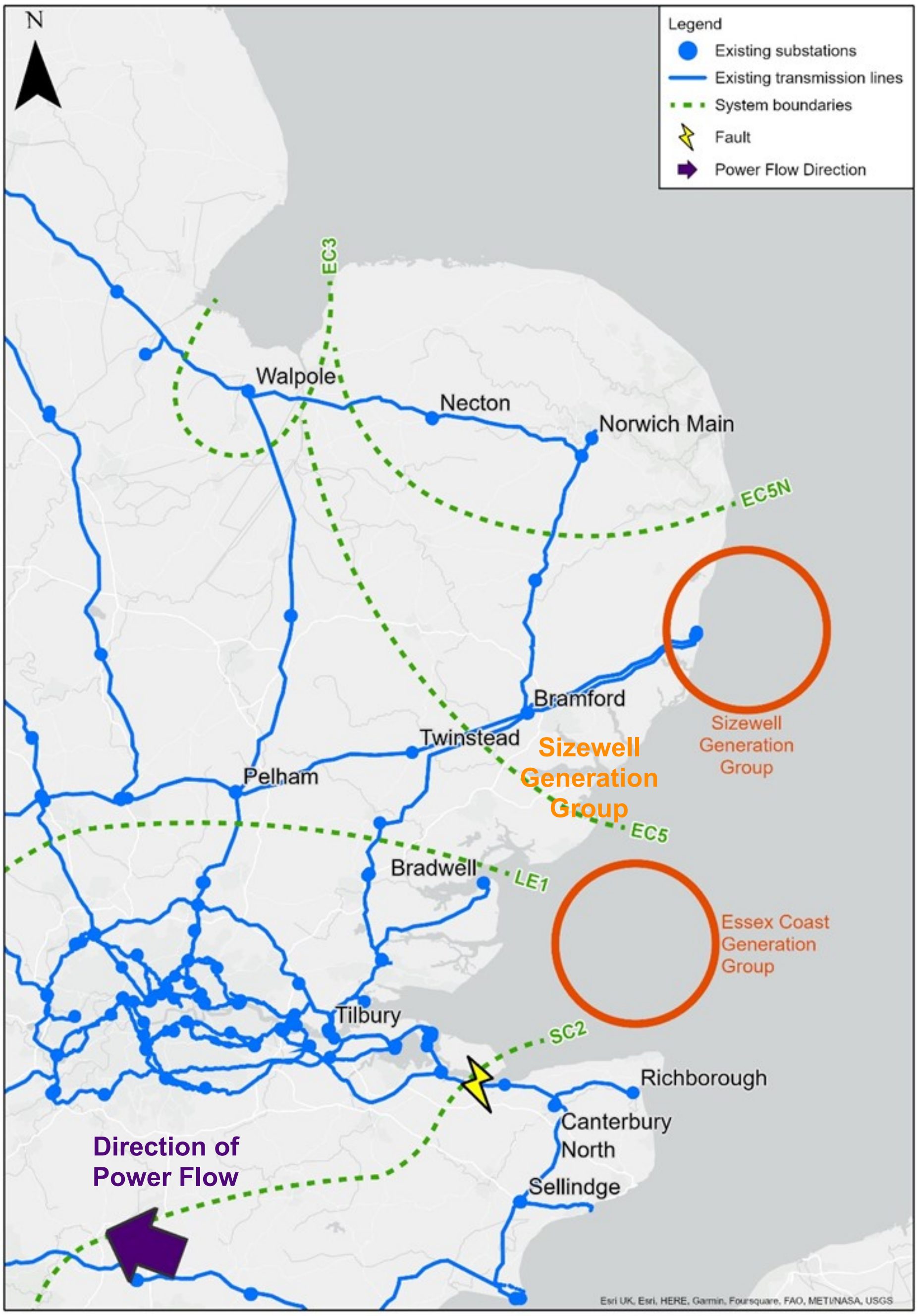
2037	TH Ninfield	Ninfield	Energy Storage	200.0 MW	0.83	166.0 MW
2037	Henley Downs Farm BESS	Ninfield	Energy Storage	240.0 MW	0.83	199.2 MW
2037	Ninfield BESS	Ninfield	Energy Storage	225.0 MW	0.83	186.8 MW
2037	Partridge Farm BESS	Sellindge	Energy Storage	500.0 MW	0.83	415.0 MW
Total Existing Generation (MW)				**5,693.8 MW**		**5,279.8 MW**
Total Generation Impacting SC2 (MW)				**18,390.9 MW**		**15,899.4 MW**
Forecast SC2 ACS Peak Demand 2030/31						**1,556.1 MW**
Existing Planned Transfer at ACS Peak with All Generation (Existing Generation - Existing Demand)						**4,068.3 MW**
SC2 Transfer at ACS Peak 2031 all generation						**14,343.3 MW**

Figure 3.6 SC2 boundary fault and impact



3.7.20 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 5,873 MW. The transfer required by 2037 following the closure of Dungeness Nuclear Power Station is 14,343.3 MW. This is in excess of both the capability and capacity of SC2 causing both overloads and voltage stability issues on the south coast.

3.7.21 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 significant 8,470.3 MW of capacity from the SC2 area by 2037.

3.8 Need case conclusion

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

- Provision of 9,928 MW of capacity across East Anglia EC5 Boundary and 7,520 MW of capacity across EC5N Boundary
- Provision of 7,476 MW of capacity across the LE1 Boundary
- Provision of 352.1 MW of capacity to the Sizewell Generation Group
- Provision of 3,480 MW of connection capacity from the Essex Coast Generation Group
- Provision of 8,470 MW of capacity from the SC2 Boundary Group.

3.8.2 The remainder of this report considers the backcheck, review and interactivity of options to resolve the need case set out above. NGET 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 failing to resolve the need would breach this requirement.

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 project 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 are described within the 2024 Strategic Options Backcheck and Review, within Appendix B. 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 Chapter provides the chronological history of the options that are evaluated in this 2025 Strategic Options Backcheck and Review and how the process has been used to arrive at this list.

4.2 Corridor and Preliminary Routeing and Siting Study

4.2.1 In 2022, as part of the wider Network Planning Process, we carried out an initial assessment of the strategic options available to meet the need case set out in Chapter 3 above. This drew on the economic analysis of the ESO in the NOA process and was presented in the April 2022 Corridor and Preliminary Routeing and Siting Study (CPRSS). This assessment identified 27 combinations of circuit options across a wide geographical area, later reduced to 23 (3 for west, 5 for north and 15 for east). For example, 'East 7' was a combination of AENC (Norwich – Bramford), ATNC (Bramford – Tilbury), SCD1 (Richborough – Sizewell) and TENC (Tilbury – Grain).

4.2.2 For each of these combinations of options we undertook an appraisal of deliverability, considered the system benefit that the reinforcement provided, and considered environmental and socio-economic factors. We considered whether in-principle environmental and socio-economic constraints with the potential to materially affect strategic options were present. We concluded that none were significant enough to materially influence strategic option selection. For example, whilst some relatively extensive areas of built development are present (Ipswich, Colchester etc) they can be avoided. In the case of national landscape designations (e.g. Dedham Vale; Suffolk Coast and Heaths; Surrey Hills; Kent Downs) we considered the relative location of these in combination with the potential to adopt alternative technology to OHL meant that none presented a reason (either alone or in combination) or otherwise indicated an option should not be progressed. Further detail of this exercise is given in the CPRSS.

4.3 NOA Cost Benefit Analysis

4.3.1 As part of the annual NOA cycle, each combination of options proceeded through the Cost Benefit Analysis (CBA) carried out by the ESO. This used the 'BID3' economic model, which is an economic dispatch optimisation model that simulates European energy markets, including demand, supply and infrastructure. It models the hourly generation of all power stations on the system, taking into account factors such as fuel prices, historical weather patterns and operational constraints. This allows avoided predicted constraint costs to be calculated for each option across the range of FES, based on their costs and delivery dates. NESO, and its predecessor ESO's role, and both NOA and the FES, are discussed in Chapter 2 above.

4.3.2 Predicted constraint savings from each pathway were compared to the capital costs to assess whether 1) investment is economically optimal versus a 'do nothing' counterfactual (i.e. no capital costs are expended and constraint costs are incurred), and 2) if so, which option/pathway is economically optimal. Net Present Value (NPV) is calculated by deducting the present value of capital costs from the present value of predicted constraint costs for each option in each FES. Options were compared using a 'Least Worst Regrets' method, being ranked in order of the highest (i.e. worst) regret for each option, in comparison to all other options, across the four FES (i.e. if an option was the best in all FES, its Least Worst Regret would be 0).

4.3.3 Table 4.1 below shows the outcome of this analysis.

Table 4.1 ESO Least Worst Regrets Analysis per Option in £m.

Reinforcement Strategy Option	Net Regret Cost by FES[19] (£m)				Worst Regret Cost (£m) ordered by least-worst regret
	CT	LW	SP	ST	
East 7	36	143	51	0	143
North 5	233	340	248	197	340
East 3	296	556	0	355	556
East 15	499	664	96	504	664
East 6	0	0	711	155	711
East 9	819	914	710	606	914
East 8	863	995	737	692	995
East 2	746	1,000	422	803	1,000
East 14	923	960	1,126	730	1,126
North 2	804	789	1,314	709	1,314
East 10	1,237	1,330	1,111	1,028	1,330
North 1	687	654	1,376	664	1,376
East 11	1,549	1,642	1,423	1,340	1,642
West 3	1,477	1,660	1,428	1,374	1,660
East 13	1,691	1,820	1,549	1,524	1,820
East 12	1,715	1,749	2,315	1,685	2,315
West 2	1,413	1,430	2,951	1,646	2,951
North 4	1,458	1,228	3,705	1,718	3,705
West 1	1,487	1,421	3,978	1,908	3,978

[19] The four Future Energy Scenarios as described in the 2020 versions of the Future Energy Scenarios. The scenarios are: Steady Progression (SP) - slowest credible decarbonisation; System Transformation (ST) – Hydrogen for heating; Consumer Transformation (CT) – Electrified heating; and, Leading the Way (LW) – Fastest credible decarbonisation.

Reinforcement Strategy Option	Net Regret Cost by FES[19] (£m)				Worst Regret Cost (£m) ordered by least-worst regret
	CT	LW	SP	ST	
North 3	1,909	1,678	4,151	2,165	4,151
East 4	2,159	1,812	5,083	2,453	5,083
East 5	2,179	1,661	6,515	2,645	6,515
East 1	2,633	2,114	6,961	3,096	6,961

4.3.4 This economic assessment led to investment recommendations on whether individual reinforcements should proceed.

4.3.5 The NOA analysis showed that combinations of options to the East and North were economically optimal, and that onshore overhead line options are preferred to offshore HVDC solutions.

4.3.6 The highest-ranking option from an economical perspective, with an LWR of £143m, was the 'East 7' option. The schemes included in the East 7 option are shown below with their columns being project description and cost, NOA code, proposed option, circuit technology.

Table 4.2 Strategic Combination Proposal East 7

East 7 Capex £2,189.75m As East 6 with enhanced export capacity from EC5	AENC	Norwich-Bramford	AC OHL (Onshore)
	ATNC	Bramford-Tilbury	AC OHL (Onshore)
	SCD1	Richborough-Sizewell	HVDC Cable (Offshore)
	TENC	Tilbury-Grain	AC OHL (Onshore)

4.3.7 The 'East 6' option is similar to East 7 with TENC excluded (i.e. AENC, ATNC and SCD1 only). This is the LWR option in two of the FES scenarios tested (Leading the Way and Consumer Transformation).

4.3.8 The second highest ranking option was 'North 5', incorporating ATNC, SCD1 and TENC (as per East 7), but with NPNC Necton-Pelham OHL replacing AENC.

4.3.9 Third highest ranked was 'East 3', incorporating ATNC and TENC (as per East 7), but with NTDC Necton-Tilbury HVDC Cable (Onshore) and CAKE Canterbury-Kemsley AC OHL.

4.3.10 The best performing option in the West ('West 3'), combining ATNC and TENC with NCDC Norwich-East Claydon HVDC OHL (Onshore), IBNC Iver-West Weybridge-Bolney AC OHL (Onshore) had an LWR of £1,660m.

4.4 CPRSS conclusion

4.4.1 Taking all factors into account, the balanced conclusion across the range of scenarios was that the preferred reinforcement solution was provided by Option East 7. This solution combined offshore and onshore connections with three distinct elements: an offshore reinforcement between the south coast and East Anglia (SCD1); onshore reinforcement between Tilbury and Grain (TENC); and onshore reinforcement between Norwich and Tilbury (AENC/ATNC) via Bramford substation and a new East Anglia Connection Node substation.

4.5 NOA and HND recommendations

4.5.1 AENC, ATNC and SCD1 were given proceed signals in NOA 2021/22, and the July 2022 NOA Refresh also identified these reinforcements as ‘Holistic Network Design essential’ (HND essential) options. TENC does not have a proceed signal nor is it considered as required currently in the NOA Refresh and is therefore not being taken forward at this time. It does not form part of the Norwich to Tilbury project.

4.5.2 The analysis for the NOA and HND provided a foundation for identifying strategic options that are most viable and should be taken through further analysis.

4.6 Options assessment process

4.6.1 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.

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

4.6.3 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.

4.6.4 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 Circuit 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.

4.6.5 All options taken forward for appraisal are evaluated in respect of environmental constraints, socio economic effects, technology alternatives, capital and Circuit 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.

4.6.6 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.
  - Capital and Circuit Lifetime Costs considers 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

4.6.7 Circuit Lifetime Costs, including circuit capital cost, cost of loses over 40 years and cost of operation over 40 years.

4.6.8 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

4.6.9 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

4.6.10 A full evaluation and costs used in our assessments can be found in the Appendix E in the 2024 Strategic Options Backcheck and Review (Appendix B).

4.6.11 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.

4.6.12 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.

4.6.13 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.

4.6.14 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).

4.6.15 The options in the following Chapters 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 and are now subject to a further backcheck and review.

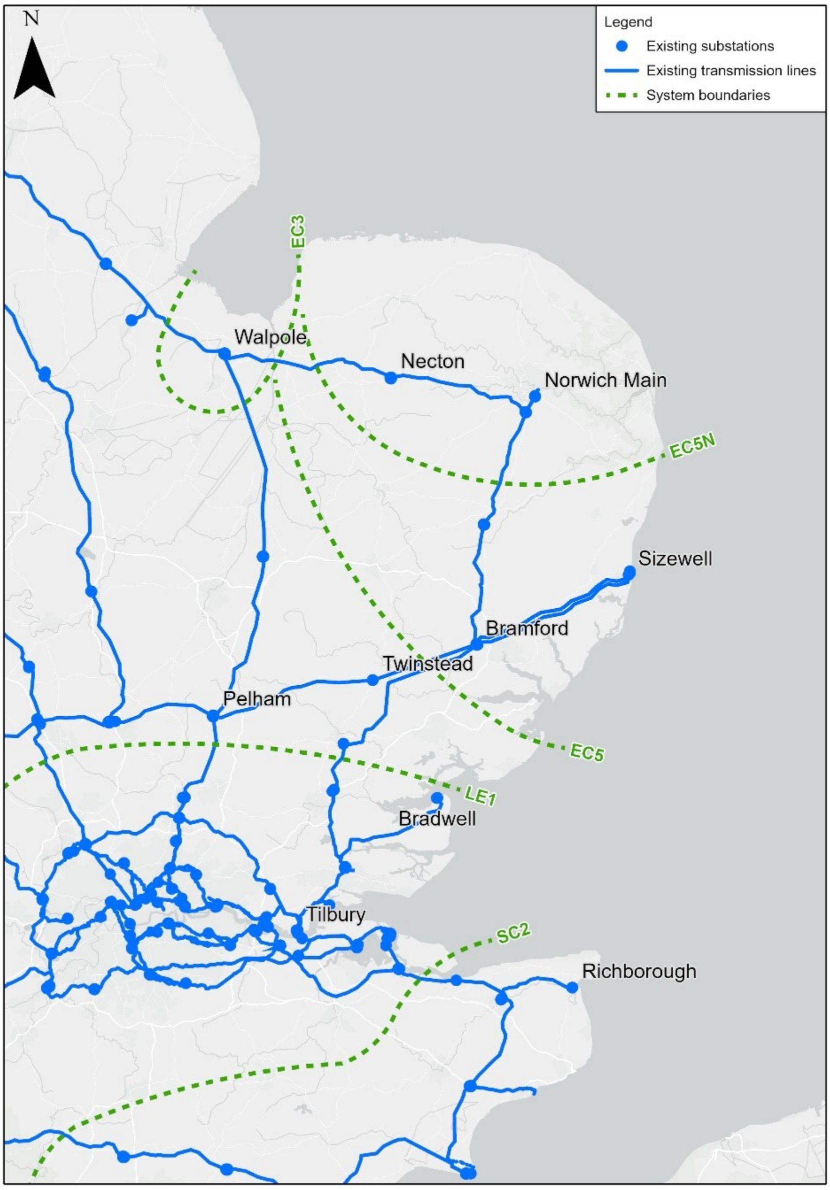
5. Strategic option overview

5.1 Introduction

5.1.1 As described in Chapter 3 above, the transmission system is in need of reinforcement to ensure ongoing SQSS compliance as the volume of generation connecting in the area increases.

5.1.2 Figure 5.1 below shows the transmission network in the East Anglia and the Southeast region including all works completed to maximise existing system capability including Bramford to Twinstead new overhead line, which is required to meet the needs of earlier connections of generation and interconnectors.

Figure 5.1 Considered East Anglia and Southeast Transmission System and system boundaries



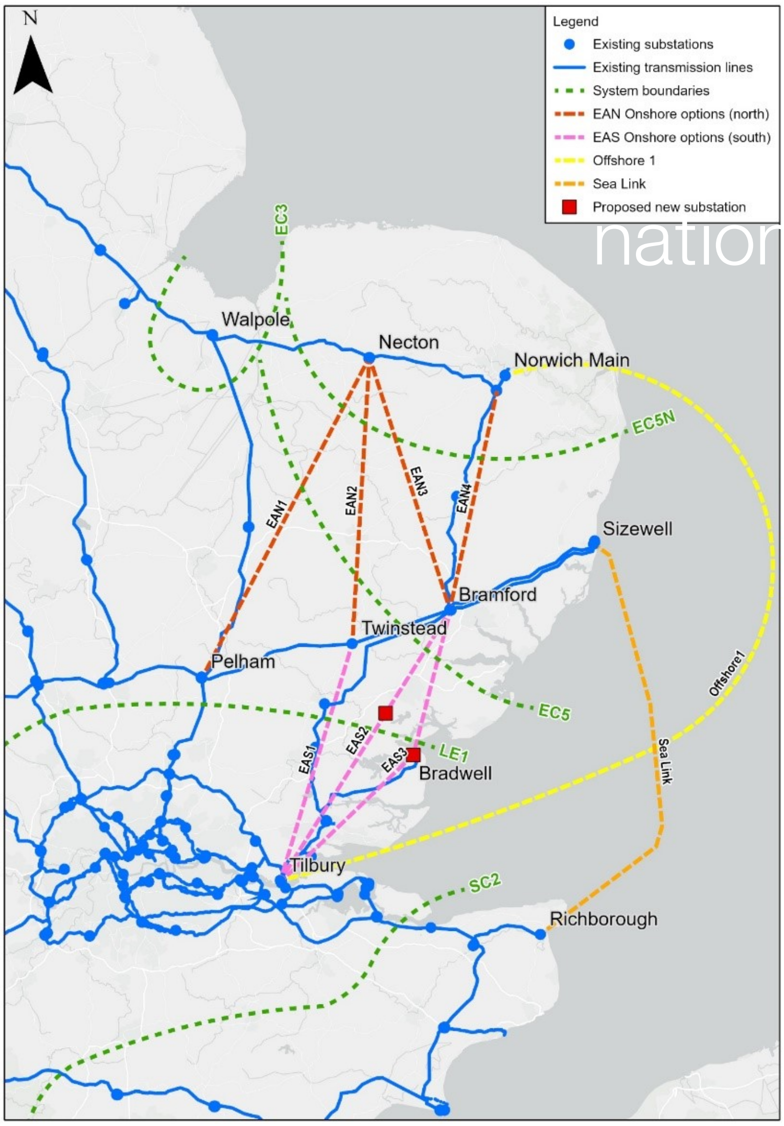
5.2 Connection options considered for detailed appraisal

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

5.2.2 A combination of options is required to resolve individual power constraints across the boundaries indicated in Figure 5.2. Firstly, solutions to resolve capacity shortfalls across EC5 North, then across EC5 and LE1 combined. 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.

5.2.3 The report reviews each individual circuit option which can provide solutions to the North and East, including some additional options that did not form part of the previous analysis, as indicated below. Options in the West have not been carried forward to this stage in the process on the basis of the ‘benefits’ filter, given that the CPRSS and NOA CBA process showed these options to be significantly suboptimal, or because they offered no benefits over other options (e.g. a Norwich-Necton option offered no benefits over those northern options listed below).

Figure 5.2 Connection options



Circuits to the North of East Anglia

- EAN 1 – Necton to Pelham 115 km
- EAN 2 – Necton to Twinstead 90 km
- EAN 3 – Necton to Bramford 85 km
- EAN 4 – Norwich Main to Bramford 80 km

Circuits to the South of East Anglia

- EAS 1 – Twinstead to Tilbury 80 km
- EAS 2 – Bramford via New Substation to Tilbury 100 km
- EAS 3 – Bramford via New Substation at Bradwell to Tilbury 130 km
- Offshore coastal East Anglia
- Offshore1 – Norwich Main to Tilbury 220 km

6. 2025 Backcheck and review

6.1 Introduction

6.1.1 The following sections of this report deal with the backcheck and review of each strategic option, detailing any changes to environmental, socio-economic, technical and cost appraisals since the 2024 Strategic Options Backcheck and Review that may influence the selection of the preferred strategic option.

6.1.2 National Grid has established that routeing a new connection from an offshore cable route into the Tilbury substation is becoming increasingly constrained. New built development, approved development applications (such as Tilbury Freeport), undetermined, as of July 2025, planning applications and the potential for environmental designation, are all providing increasingly restrictive constraints to future connections seeking to make a landing point from the marine environment into Tilbury substation.

6.1.3 Our previous strategic options backchecks and reviews have consistently shown that a connection at Tilbury substation from offshore cable connections have multiple environmental, socio-economic, design, resilience and financial challenges which do not provide sufficient certainty on delivery and impact to enable them to be appropriately taken forward to meet the urgent need for the connection. The level of difficulty and uncertainty associated with such an offshore connection has increased which means the technical, programme, environmental and financial risks continue rule it out.

6.2 Environmental appraisal

Landscape and visual

6.2.1 The strengthened Furthering the Purpose Duty under s85 of the Countryside and Rights of Way Act 2000 (implemented via the Levelling-up and Regeneration Act 2023) is in force. The strengthened duty requires relevant authorities to actively "seek to further" rather than "have regard to" the conservation and enhancement of a National Landscape's purposes and natural beauty. NGET's established approach to avoiding or minimising impacts on designated landscapes through careful routing, design and where necessary undergrounding, remains consistent with both the previous and strengthened statutory requirements. The policy change reinforces existing good practice rather than requiring a fundamental change in approach to strategic option assessment.

6.2.2 The strengthened duty's influence on decisions of how the preferred option is to be taken forward into the consenting regime is (including elements that seek to further the purposes of the National Landscape) is also a matter for the detailed design of the chosen strategic project and is explained in the Design Development Report (DDR)[20].

[20] Design Development Report (DDR) - Document reference: 5.15

6.2.3 After considering the strengthened duty in light of the above, the assessment conclusion from the 2024 Strategic Options Backcheck and Review remains unchanged.

Historic environment

6.2.4 No new statutory designations, extensions to existing designations, or withdrawals of designations have been identified within the study areas that would materially affect corridor routing at a strategic level.

6.2.5 Review of consented developments within the study area of each of the options has not identified any new NSIP/DCO projects that would fundamentally impact the strategic viability of any option from a historic environment perspective, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

Ecology

6.2.6 No new statutory designations, extensions to existing designations, or withdrawals of designations have been identified within the study areas that would materially affect corridor routing at a strategic level.

6.2.7 Review of consented developments within the study area has not identified any new NSIP/DCO projects that would fundamentally impact the strategic viability of this option from an ecological perspective, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

Physical environment

6.2.8 The Environment Agency updated their national flood mapping in 2025, including updates to the Flood Map for Planning, the Risk of Flooding from Rivers and Sea mapping and the Risk of Flooding from Surface Water mapping. The changes to the flood mapping were reviewed when the new datasets were published. The new mapping resulted in some infrastructure moving into higher risk zones and other infrastructure moving into lower risk zones. The changes are such that the updated flood mapping does not have significant implications for corridor routing. There have been no fundamental changes in local plans or policy frameworks, nor have there been significant environmental changes that could impact corridor routing since 2024, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

6.3 Environmental appraisal

Settlements and populations

6.3.1 The backcheck reconsidered Socio-economic factors within the study area, including the densely populated towns and cities linked to each of the strategic options and found that the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

Tourism and recreation

6.3.2 The 2024 assessment noted that there are a number of tourism and recreational assets within the study area of each of the strategic options.

6.3.3 There may have been minor changes to the baseline from the 2024 assessment; however, the potential changes are not likely to fundamentally change the strategic options assessment from a tourism and recreation perspective, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

Land use

6.3.4 No significant changes to agricultural land classifications or other land use designations have been identified within the study area for each of the strategic option that would materially affect corridor routing at a strategic level.

6.3.5 Review of consented developments within the study area have not identified any new NSIP/DCO projects that would fundamentally impact the strategic viability of any strategic option from a land use perspective, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

Infrastructure

6.3.6 The Bramford to Twinstead connection was granted development consent in September 2024.

6.3.7 No additional major infrastructure developments have been identified within the study area for each of the strategic options that would materially affect corridor routing at a strategic level.

6.3.8 Review of consented developments within the study area has not identified any new NSIP/DCO projects that would fundamentally impact the strategic viability of any strategic option from an infrastructure perspective, therefore the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

6.4 Technical scope and costs

6.4.1 No new technology has been identified, and our cost base remains in financial year 2020/21 prices as we continue to align with Ofgem's network price controls 2021-2026 (RIIO-T2[21]) therefore, the assessment conclusions from the 2024 Strategic Options Backcheck report remains unchanged.

[21] The RIIO-T2 is the price control for high voltage electricity transmission networks which transmit energy across Britain from where it is generated. The price control runs for five years from 2021-2026. https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2

7. Conclusion and next steps

7.1 Conclusion

7.1.1 As explained in Chapter 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.

7.1.2 This report has considered options to meet the Need Case set out in Chapter 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.

7.1.3 We have considered the information which is available to us at this stage of the process. We have outlined in this report changes that may have affected our evaluation for each option since the previous 2024 Strategic Options Backcheck and Review. 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 revised National Policy Statements EN-1, EN-3 and EN-5.

7.1.4 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, the conclusion following the update is that the combination of **EAN 4 OHL Norwich Main to Bramford** and **EAS 2 OHL Bramford via a new substation to Tilbury** remains the preferred strategic options for the Norwich to Tilbury project.

7.1.5 Alongside SCD1/Sea Link or an alternative connection from Sizewell area to north Kent 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.

7.1.6 The combination of EAN 4, EAS 2 and Sea Link resolves the needs case set out below.

- Provision of 9,225 MW of capacity across East Anglia EC5 Boundary and 4,931 MW of capacity across EC5N Boundary.
- Provision of 7,476 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,480 MW of connection capacity for the Essex Coast Generation Group
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

7.2 Next steps

7.2.1 Norwich to Tilbury has been subject to consultation, and this report confirms that EAN4 and EAS2 remain the optimal options to progress to meet the need case outlined in Chapter 3. Norwich to Tilbury will now be taken forward to the next stage of development.

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Appendix A. Glossary of Terms and Acronyms

nationalgrid

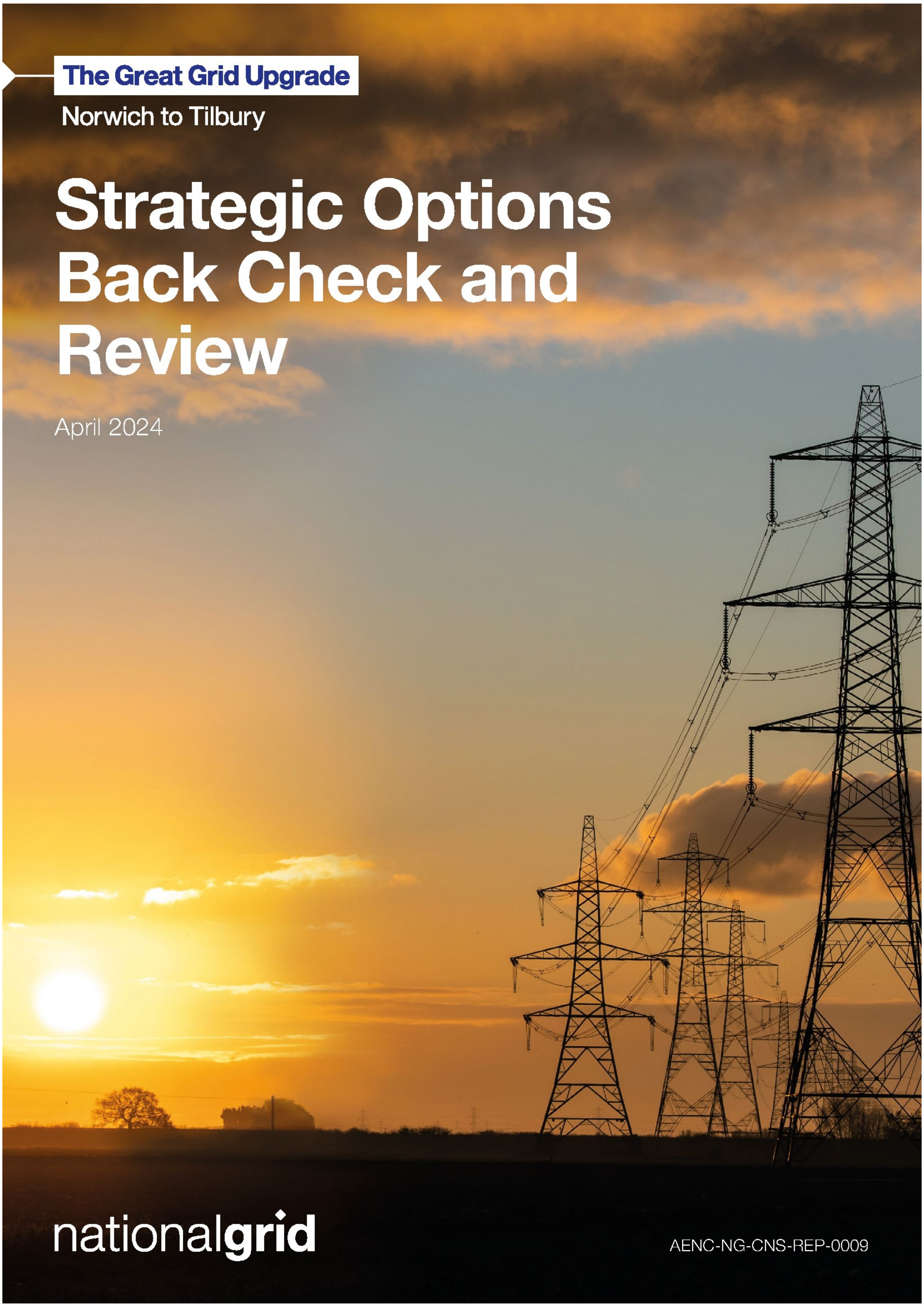
Appendix A
Glossary of Terms and Acronyms

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
FES	Future Energy Scenarios
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 (2012)
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) = 1,000volts
watt (W)	The SI unit of power 1 kilowatt (kW) = 1,000watts 1 megawatt (MW) = 1,000kW 1 gigawatt (GW) = 1,000MW
XLPE	Cross Linked Polyethylene (solid material used to provide electrical insulation)

Appendix B. 2024 Strategic Options Backcheck and Review

Appendix B
2024 Strategic Options Backcheck and Review



Contents

Executive summary

Purpose of this report

This Strategic Options Backcheck and Review is a technical report providing an overview description of the options that National Grid Electricity Transmission (NGET) has identified and subsequently evaluated for reinforcement of the network in the East Anglia region. This revision has undertaken an update of the latest Needs Case and on the latest generation and network requirements. The backcheck established that the Needs Case is still valid and the options identified continue to resolve the Needs Case as set out. Our cost base remains 2020/21 for evaluation purposes and is therefore unchanged, technology remains unchanged, Environmental and Socio-Economic remains as evaluated previously. Therefore, this backcheck and review has largely remained limited to an update of the needs case.

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

Figure 1 – Approach to consenting process

This report forms part of the initial 'Options identification and selection' stage and 'Defined proposal and statutory consultation' 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 East Anglia needs to change;
- a summary description of options for providing additional transmission system capability that we identified as strategic options;
- how NGET 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

NGET 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.

NGET, 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 1989.

Electricity System Operator (ESO)

The Electricity System Operator (ESO) is a separate legal entity to NGET, but as of 2024 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 NGET, 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 have 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 50GW of offshore wind by 2030's as a key part of a strategy for secure, clean and affordable British energy for the long term.

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 132kV connected gas fired power stations.

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. In the East Anglia region, connection agreements have been signed for 22,907.6 MW of new generation (total generation of 30,595 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).

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). This means that generation in the area will significantly exceed demand.

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. 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.

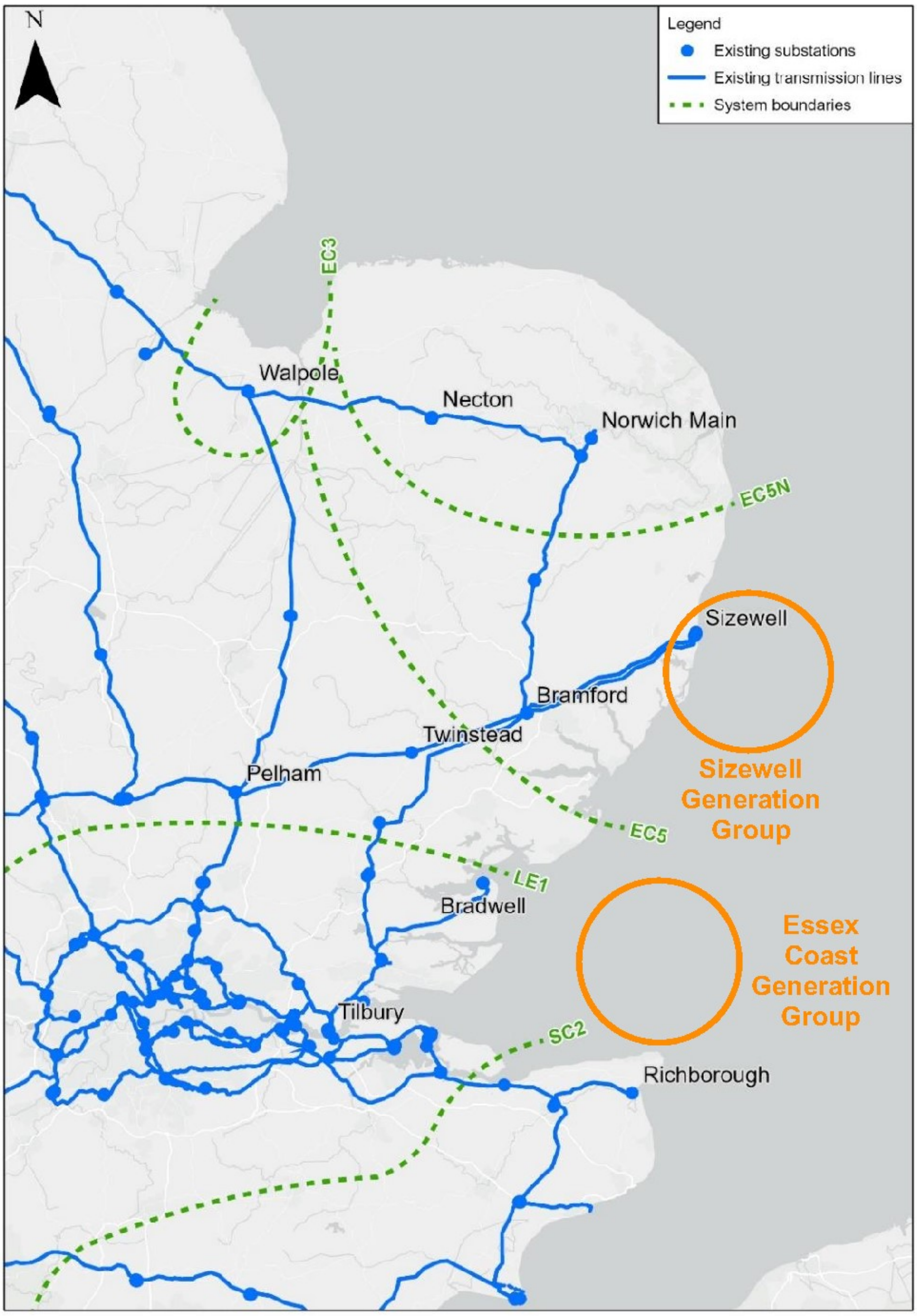
The concept of 'boundary capacity and capability' plays an important role in system planning. A boundary notionally splits the system into two parts, crossing critical circuit paths that carry power between the areas where power flow limitations may be encountered. Where 'boundary capacity' – the capacity 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 and Essex coast. These are illustrated in the network diagram in Figure 2 below.

All diagrams within the report show the existing system following the completion of the Bramford to Twinstead project, which is included in the background considered for this projects Needs Case. The Bramford to Twinstead project is still subject to its own Development Consent Order which commenced in April 2023. However, should consent be granted, the Bramford to Twinstead project is proposed to be constructed and operational, ahead of the connection of any proposed infrastructure within this report.

Figure 2 – East Anglia and South-East region transmission system and system boundaries



We have assessed the possible impacts associated with the connection of the total volume of new generation on these 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 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.

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

- Provision of 9,225 MW of capacity across East Anglia EC5 Boundary and 4,931 MW of capacity across EC5N Boundary.
- Provision of 7,476 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,480 MW of connection capacity for the Essex Coast Generation Group
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

In summary, this analysis shows that without reinforcement, the capacity of the East Anglia existing network 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 consecutive 'proceed' signals to new 400 kV circuits in north and south East Anglia in the 2020/21 and 2021/22 Network Options Assessment (NOA) publications. The July 2022 NOA Refresh also identified reinforcements in this area as an HND essential option, meaning that it considers the project as essential to meet the UK Government's 2030 offshore wind targets.

We are therefore required to assess the reinforcement options available for providing the additional capability required.

Initial strategic options analysis

In 2022, as part of the wider Network Planning Process, we carried out an initial assessment of the strategic options available to meet the need case set out above. This drew on the economic analysis of the ESO in the NOA process, and was presented in the April 2022 Corridor and Preliminary Routeing and Siting Study (CPRSS).

This assessment identified 27 combinations of circuit options across a wide geographical area, later reduced to 23 (3 for west, 5 for north and 15 for east). This analysis covered both East Anglia and the South East.

For each of these combinations of options we undertook an appraisal of deliverability, considered the system benefit that the reinforcement provided, considered environmental and socioeconomic factors and considered the cost benefit analysis completed by the ESO.

As part of the annual network planning cycle mentioned above, each combination of options proceeded through a NOA Cost Benefit Analysis (CBA) carried out by the ESO. Through this process the ESO makes investment recommendations to transmission owners (TOs) including NGET as to whether there is an economic case for individual reinforcements to proceed. These recommendations are considered by TOs in their assessment of reinforcement options.

The NOA CBA carried out by the ESO compared the combination of options using a 'Least Worst Regrets' method, being ranked in order of the highest (i.e. worst) regret for each option, in comparison to all other options, across the four FES (i.e. if an option was the best in all FES, its Least Worst Regret would be 0). This analysis concluded that the overall Least Worst Regret option across the four FES was a combination of Norwich – Bramford (AENC), Bramford – Tilbury (ATNC), Richborough – Sizewell (SCD1) and Tilbury – Grain (TENC) as shown in Table 1

Table 1 – NOA Lead Option as Reported in the CPRSS

AENC	Norwich-Bramford	AC OHL (Onshore)
ATNC	Bramford-Tilbury	AC OHL (Onshore)
SCD1	Richborough-Sizewell	HVDC Cable (Offshore)
TENC	Tilbury-Grain	AC OHL (Onshore)

More broadly, this analysis showed that combinations of transmission options to the east and north of the East Anglia region were economically optimal, and that onshore overhead line options would be preferred to offshore HVDC solutions.

The CPRSS concluded, taking all social-economic, environment, technical and cost factors, into account that the preferred solution was a combination of offshore and onshore connections with three distinct elements: an offshore reinforcement between the south coast and East Anglia (SCD1 and referred to as Sea Link); onshore reinforcement between Tilbury and Grain (TENC); and onshore reinforcement between Norwich and Tilbury (AENC/ATNC) via Bramford substation and a new East Anglia Connection Node substation.

AENC, ATNC and SCD1 were given proceed signals in NOA 2021/22, and the July 2022 NOA Refresh also identified these reinforcements as 'HND essential' options, meaning that the ESO considers them to be essential to meet the UK Government's 2030 offshore wind targets. TENC does not have a proceed signal nor is it considered as required currently in the NOA Refresh and is therefore not being taken forward at this time.

The analysis for the NOA and HND provided a solid foundation for identifying strategic options that are most viable and should be taken through further analysis.

Backcheck and review of strategic options

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

This report considers solutions to resolve capacity shortfalls across the EC5 North boundary, then across EC5 and LE1 combined – i.e. focusing on the East Anglia area. As noted above, a solution crossing boundary SC2 in the South East, as well as LE1 and EC5, is also necessary to meet the identified requirement to increase the capacity across these boundaries. The optimal technical solution to meet this need – currently SCD1/Sea Link – will be considered separately via the project development work for that project. Given that all potential options crossing SC2 would connect at Sizewell, the combination of onshore and offshore options to meet the remaining East Anglia need are the same regardless of the eventual southern landing point. Due to the interrelation between these projects, we have undertaken an interactivity assessment of Sea Link.

The onshore options to resolve EC5 North boundary requirements are:

- EAN 1 – Necton to Pelham 115km
- EAN 2 – Necton to Twinstead 90km
- EAN 3 – Necton to Bramford 85km
- EAN 4 – Norwich Main to Bramford 80km

For onshore options, four technological solutions are considered: AC Overhead Line; AC Underground cable; AC Gas insulated line (GIL); and HVDC Underground Connection.

The onshore options to resolve EC5 and LE1 boundary requirements are:

- EAS 1 – Twinstead to Tilbury 80km
- EAS 2 – Bramford via New Substation to Tilbury 100km
- EAS 3 – Bramford via a New Substation at Bradwell to Tilbury 130km

One offshore option is also considered:

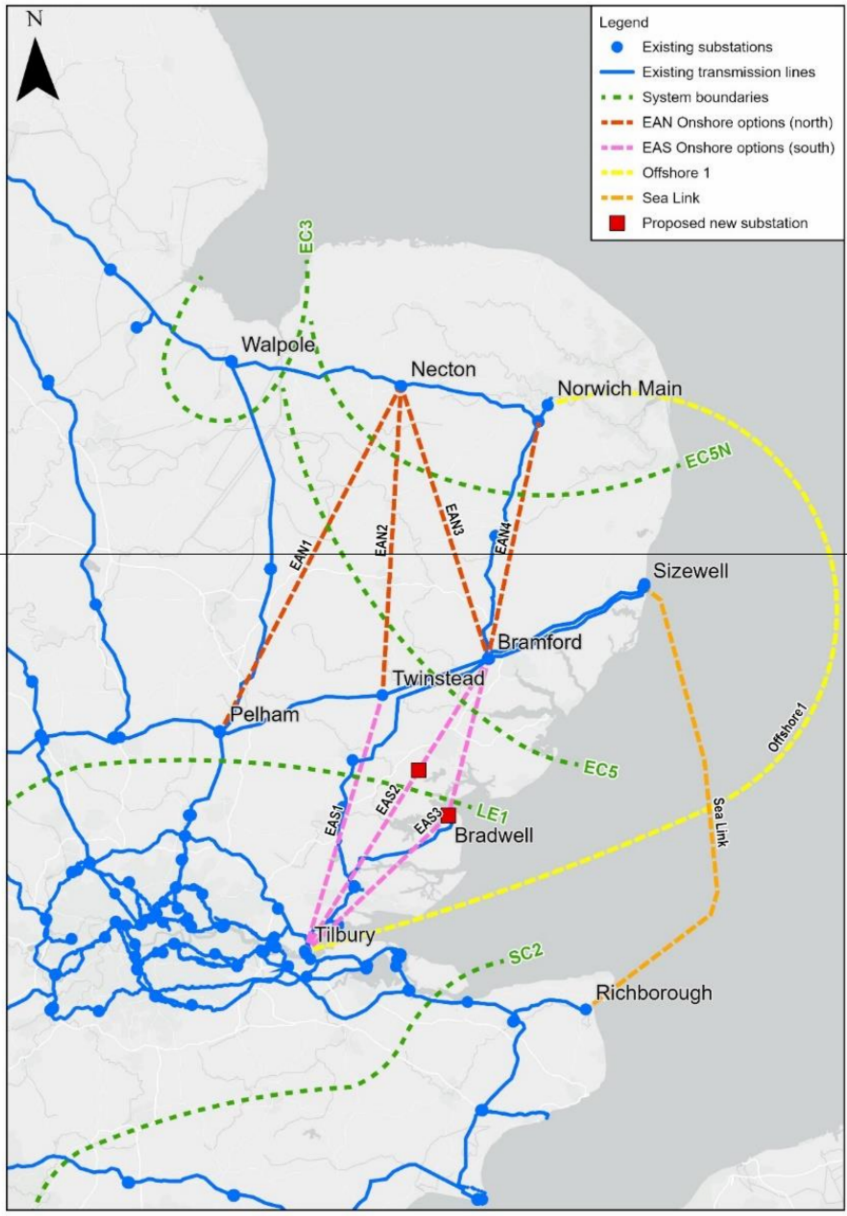
- Offshore 1 – Norwich to Tilbury, crossing boundaries EC5 North, EC5N and LE1

Two technology options are considered for this option: AC Subsea cable and HVDC Subsea cable.

Any combination of one northern (EAN) and one southern (EAS) onshore options can be used to meet the need onshore, whilst Offshore 1 is required to meet the need offshore. SCD1/Sea Link or an equivalent is required in all cases and is therefore not considered a differentiator.

These options are all shown in Figure 3 below.

Figure 3 – Strategic options



An environmental assessment of each alternative has been carried out. This covered the following topics: Landscape and Visual, Historic Environment, Ecology, Physical Environment, Marine Environment (where appropriate), Settlement and Population, Tourism and Recreation, Land Use, Infrastructure and Shipping/Navigation (where appropriate).

Whilst all options would have impacts, none present in-principle environmental issues that could not be mitigated with careful consideration of routeing and use of appropriate technologies to specific constraints, as is consistent with the National Policy Statements (NPSs) against which proposals for nationally significant infrastructure projects are assessed.

Table 2 – Cost Summary of combination of works required to meet project need

<table>
<tr><th>Boundary or Group</th><th colspan="12">Onshore Options</th><th>Offshore</th></tr>
<tr><th>EC5N & EC3</th><td colspan="3">EAN 1 Necton to Pelham</td><td colspan="3">EAN 2
Necton to Twinstead</td><td colspan="3">EAN 3
Necton to Bramford</td><td colspan="3">EAN 4
Norwich Main to Bramford</td><td rowspan="5">Offshore 1
Norwich Main to Tilbury</td></tr>
<tr><th>Economic Technology (Capacity)</th><td colspan="3">OHL
115km
(6930 MW)</td><td colspan="3">OHL
90km
(6930 MW)</td><td colspan="3">OHL
85km
(6930 MW)</td><td colspan="3">OHL
80km
(6930 MW)</td></tr>
<tr><th>Capital Cost including non-circuit works</th><td colspan="3">£494.5m</td><td colspan="3">£494.2m</td><td colspan="3">£375.1m</td><td colspan="3">£355.2m</td></tr>
<tr><th>Circuit 40yr Lifetime NPV Cost</th><td colspan="3">£787m</td><td colspan="3">£616m</td><td colspan="3">£582m</td><td colspan="3">£548m</td></tr>
<tr><th>EC5 & LE1</th><td colspan="4">EAS 1
Twinstead to Tilbury</td><td colspan="4">EAS 2
Bramford via new substation to Tilbury</td><td colspan="4">EAS 3
Bramford via Bradwell to Tilbury</td></tr>
<tr><th>Economic Technology (Capacity)</th><td colspan="4">OHL
80km
(6930 MW)</td><td colspan="4">OHL
100km
(6930 MW)</td><td colspan="4">OHL
130km
(6930 MW)</td><td>HVDC
220km
(6000 MW)
[4000 MW]</td></tr>
<tr><th>Capital Cost including non-circuit works</th><td colspan="4">£454.4m</td><td colspan="4">£539.3m</td><td colspan="4">£658.7m</td><td>£4,096.5
[£2,882.4m]</td></tr>
<tr><th>Circuit 40yr Lifetime NPV Cost</th><td colspan="4">£548m</td><td colspan="4">£684m</td><td colspan="4">£890m</td><td>£4,661m
[£3,232m]</td></tr>
<tr><th>SC2, EC5, LE1 & Sizewell</th><td colspan="13">Sea Link
Sizewell area to Richborough area</td></tr>
<tr><th>Economic Technology (Capacity)</th><td colspan="13">HVDC
145km
2000 MW</td></tr>
<tr><th>Capital Cost including non-circuit works</th><td colspan="13">£1,420.8m</td></tr>
<tr><th>Circuit 40yr Lifetime NPV Cost</th><td colspan="13">£1,197m</td></tr>
</table>

For northern onshore options, a principal consideration is the Breckland SPA/ SAC/SSSI complex. Whilst avoidable there is the potential for impacts on the interest features associated with both habitats and species. For the Offshore 1 option, European and national designated sites are unlikely to be avoidable, in particular at the landfalls at either end. The East Atlantic Flyway (WHS Nomination) if successful is considered to combine existing protections and designations which were considered as part of the CPRSS and do not further influence decision making

A key consideration for southern onshore options is the Dedham Vale AONB, which is in the study area for onshore options EAS 1, EAS 2 and EAS 3. In the case of EAS 1 it should be possible to avoid and/or mitigate effects on the AONB through routeing. In the case of EAS2 and EAS3 the AONB could only be avoided with significantly longer routes. It is therefore likely that these options would require undergrounding in the AONB.

In the case of option Offshore 1 there would be limited opportunity to avoid the Broads National Park and Suffolk Coast and Heaths AONB. However, some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction which would reduce the potential for some visual effects.

The costs of the options are shown in Table 2. As part of the backcheck and review process, costs have reviewed and updated in accordance with the latest costing information. These may therefore, in some cases, supersede previously published costings.

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. This full backcheck and review of all options supersedes any information provided prior to April 2023.

We have previously provided cost information for comparison between onshore and offshore technologies, most recently to the Offshore Electricity Grid Task Force (OffSET). All previous costs were given for circuits only. This analysis specifically identified that offshore connection costs of at least £500m had not been included in the costs. The cost of options included in this report have been updated to ensure that both the onshore and offshore substations required to make all connections are included within the option cost. This enables the reader to fully understand the comparable option cost, without having to adjust any numbers manually.

The lowest overall onshore cost combination to meet the need is EAN 4 – Norwich Main to Bramford (£355m capital costs/£548m Circuit Lifetime Costs) and EAS 1 – Twinstead to Tilbury (£454m capital costs / £548m Circuit Lifetime Costs). However, EAS 1 is suboptimal in technical terms relative to EAS 2, the next least costly southern option, in several respects.

Firstly, EAS 2 allows the opportunity to construct a new substation in the vicinity of the coast to facilitate connections to North Falls and Five Estuaries wind farms. EAS1 would necessitate a significant amount of further infrastructure and additional costs to connect coastal generation, the Essex Coast Generation Group, further inland (likely to be greater than £500m) significantly in excess of the cost differential between EAS 1 and EAS 2.

Secondly, the proposed new substation in the vicinity of Twinstead Tee is currently included in the Bramford to Twinstead connection project, for which development consent is currently being sought. EAS 1 would require a complete re-design of Twinstead substation, significantly increasing its size and land required and introducing delay to the Bramford to Twinstead scheme, to the significant detriment of consumers in delay costs.

Thirdly, to ensure circuit continuity across EC5 boundary is maintained for a Bramford to Pelham fault, an EAN 4 and EAS 1 combination of options would require the turn-in of the Bramford to Braintree circuits to the new substation. This may require the substation location to be re-considered altogether with additional cost and complexity to this proposal.

Therefore, taking into account environmental, socio-economic, net zero government obligations, technical and cost perspectives, the optimal overall onshore combination to meet the need and facilitate the connection of North Falls and Five Estuaries is:

- EAN 4 - Norwich Main to Bramford with capital costs of £355m and Circuit Lifetime Costs of £548m; and
- EAS 2 – Bramford via a new coastal substation to Tilbury with capital costs £539.3m and Circuit Lifetime Costs of £684m.

The total capital cost would therefore be £894m, with Circuit Lifetime Costs of £1,232m.

Although it would be challenging to avoid altogether impacts on the Dedham Vale AONB as a result of EAS 2, this is not considered to be inconsistent with the relevant policies in National Policy Statements EN-1 (2024) and EN-5 (2024). If routeing to avoid the AONB is not considered viable, it would be possible to use underground cables.

Originally, the lowest cost offshore alternative option to meet the need was option Offshore 1 (Norwich Main to Tilbury) at 4000 MW with capital costs £2,882.2m and Circuit Lifetime Costs of £3,232m, in combination with SCD1/Sea Link or an alternative. However, this option no longer provides the required capacity of a minimum of 8,000 MW across LE1 and EC5, since the updated contracted generation described in the needs case section of this report has increased. This option has been included in this report as it was considered when earlier contracted positions allowed however this is no longer the case against existing contracted backgrounds. Option Offshore 1 is also suboptimal in technical terms relative to the optimal onshore combination of options (EAN 4 and EAN 2).

The offshore alternative to match the capacity of AC onshore options is a Norwich Main to Tilbury 6000 MW option, which, when combined with Sea Link, would meet the requirements of delivering 8,000 MW across EC5 and LE1 by 2050. The capital costs would be £4,097m and Circuit Lifetime Costs £4,661m, significantly in excess of the costs of onshore combinations. Option Offshore 1 is also suboptimal in technical terms relative to the optimal onshore combination of options (EAN 4 and EAN 2).

Firstly, the 6,000 MW Offshore 1 option would only facilitate the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation, with an offshore connection into the link. This would require significant additional infrastructure. The offshore HVDC platform and offshore AC platform needed to accommodate the required HVDC converter station and AC substation, would have additional capital costs of greater than £500m.

Secondly, option Offshore 1 would not provide the flexibility of onshore connection options which facilitate flows both to the West and East of the transmission system for different system faults. Offshore 1 only provides flows to the East of London, whereas energy demand is distributed throughout England so this option would not be as effective for all system conditions compared with the combination of an EAN and EAS option.

To achieve a fully like-for-like alternative with the AC North and South of East Anglia circuit options, with the additional flexibility of connecting into Bramford or substations to the west, the HVDC solution would need to be of a multi-terminal design, with 3 additional 2000 MW converters located at Bramford and cabling 50km from a DC bussing point offshore. This would significantly increase the costs and the potential environmental effects.

As noted above, whilst all potentially viable options would have potential environmental and socio-economic impacts, none present in-principle issues that could not be mitigated with careful consideration of routeing and use of appropriate technologies to specific constraints.

Taking all of this into account, we propose at the current stage to take forward an interim preference of the onshore combination of **EAN 4 OHL Norwich Main to Bramford** and **EAS 2 OHL Bramford via a new substation to Tilbury**, alongside SCD1/Sea Link or an alternative connection from Sizewell area to north Kent.

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 including in light of changes in circumstances and we will have regard to consultation responses.

The project was formerly known as East Anglia Green Energy Enablement (GREEN). We've changed the name to Norwich to Tilbury make it clear that this project is part of The Great Grid Upgrade, the largest overhaul of the grid in generations.

1. Introduction

1.1.1 This version of the Strategic Options Backcheck Review report, post non statutory consultation, has been prepared by National Grid Electricity Transmission plc (NGET) 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 Norwich to Tilbury project in East Anglia, but also includes information about wider reinforcements in the South East, which are interactive with the need case. The 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 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 to 15)
- Interaction with other projects (Section 16)
- Conclusions (Section 17)

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

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 Backcheck and Review is part of an iterative process, investigating prospective opportunities and reassessing previous provisional conclusions. The conclusions of this report will, in due course, be supplemented by feedback from consultation exercises, along with other elements such as design evolution. Consistent with Our Approach to Consenting, we will continue to assess relevant technical, environmental, socio-economic and cost factors as part of ongoing appraisals.

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 Strategy5 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:

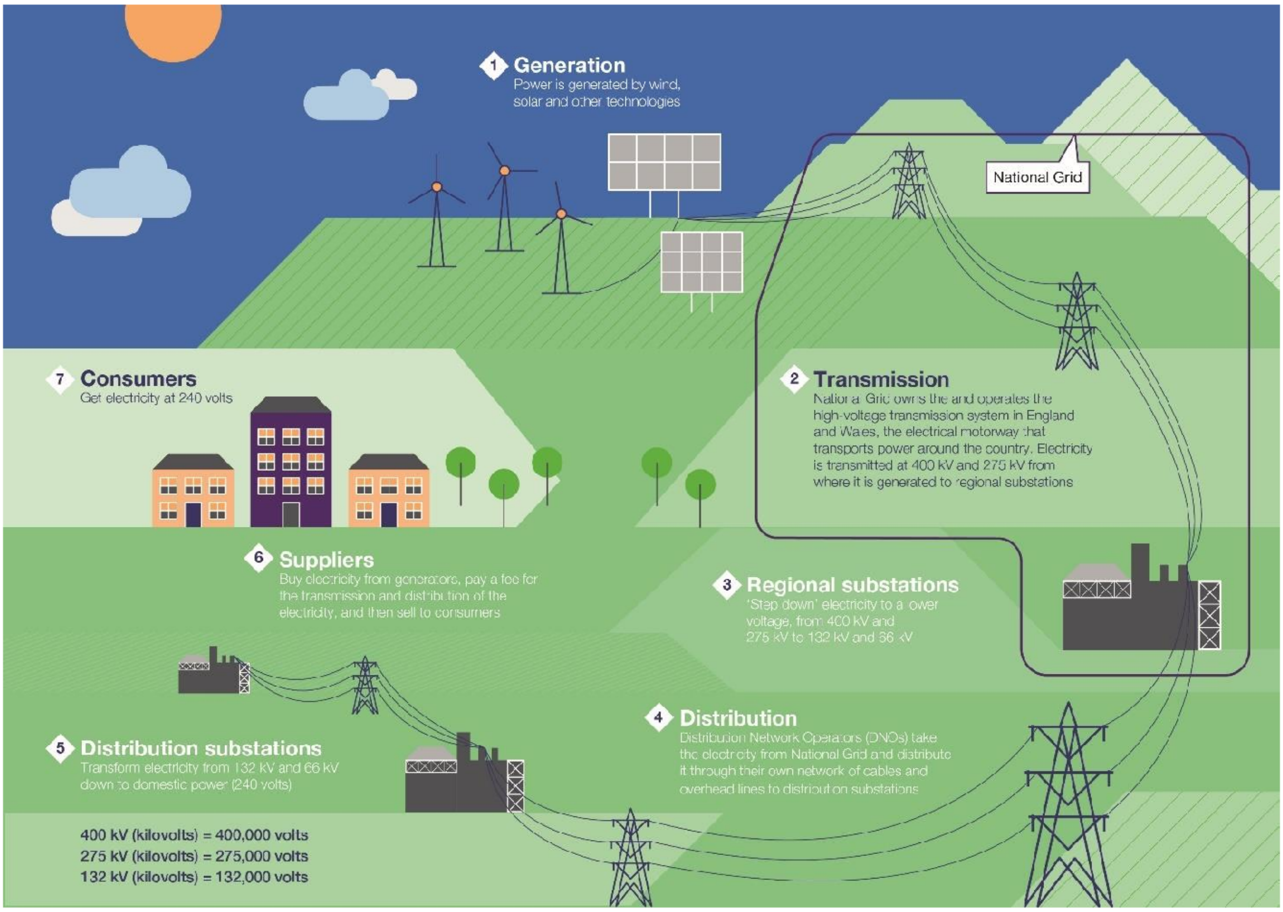
- Up to 8 Reactors of Nuclear energy being progressed reaching up to 24GW to be achieved by 2050;
- Up to 50GW of offshore wind connected by 2030 including 5GW of which will be offshore floating wind;
- Up to 10GW of low carbon hydrogen production capacity by 2030, doubling the previous ambition; and
- 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.

2.1.6 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 (NGET) 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). NGET 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, NGET is regulated by the Office of Gas and Electricity Markets (‘Ofgem’).

2.2.3 NGET’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 NGET, but as of publication 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 NGET is obligated to provide the physical connections to the elements of the NETS that NGET 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 ofNGET'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)[2].

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

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, NGET 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. NGET 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 NGET 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**[3] (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**[4] (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, 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**[5] (HND) report in summer 2022. It is now engaged in the HND Follow Up Exercise. The HND sets out a single integrated

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

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

[5] A Holistic Network Design for Offshore Wind, National Grid ESO https://www.nationalgrideso.com/future-energy/beyond-2030/holistic-network-design-offshore-wind

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**, 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 have published the **Accelerated Strategic Transmission Investment** (ASTI) decision, which aims to facilitate achieving government targets by streamlining the regulatory approval and funding process for ASTI projects. Norwich to Tilbury is an ASTI project.

2.7 National Statutory Duties (Electricity Act 1989)

2.7.1 NGET 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 NGET 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.”

2.8 National Policy Statements (NPSs)

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 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. T. The NPSs were designated in January 2024.

2.8.2 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 Backcheck and Review. An overview of main themes relevant to this backcheck and review is provided below with more detailed commentary within Appendix A to the Design Development Report published as part of the 2024 Statutory Consultation.

2.8.3 The Overarching NPS for Energy (NPS EN-1) sets out the Government's overarching policy about the development of NSIPs in the energy sector. It sets out the goal of decarbonising the energy network to achieve net zero whilst ensuring security of supply. It sets out how as the electricity system grows in scale, dispersion, variety, and complexity, work would be needed to protect against the risk of large-scale supply interruptions in the absence of sufficiently robust electricity networks. While existing transmission and distribution networks must adapt and evolve to cope with this reality, development of new transmission lines of 132 kV and above would be necessary to preserve and guarantee the robust and reliable operation of the whole electricity system. EN-1 recognises that to 'produce the energy required for the UK and ensure it can be transported to where it is needed, a significant amount of infrastructure is needed at both local and national scale. It refers to how the onshore transmission network would require substantial reinforcement in East Anglia to handle increased power flows from offshore wind generation (paragraph 3.3.68).

2.8.4 NPS EN-1 Section 4.2 sets out the Government's commitments to prioritise for low carbon infrastructure. Paragraph 4.2.1 states that "Government has committed to fully decarbonise the power systems by 2035, subject to security of supply, to underpin its 2050 net zero ambitions." Paragraph 4.2.4 states that the "Government has therefore concluded that there is a critical national priority (CNP) for the provision of nationally significant low carbon infrastructure." Paragraph 4.2.5 lists the types of infrastructure which are nationally significant low carbon infrastructure for the purposes of the CNP policy and this includes electricity grid infrastructure in the scope of EN-5, including network reinforcement, upgrade works and associated infrastructure such as substations.

2.8.5 NPS EN-3 for Renewable Energy Infrastructure, also includes support for the onshore infrastructure required to deliver new offshore wind developments. Paragraphs 2.8.34 to 2.8.43 (inclusive) reiterate the position set out in EN-1 and EN-5 that a co-ordinated approach to onshore-offshore transmission is required. The NPS also includes references to CNP Infrastructure and the application of the assessment principles outlined in Section 4 of EN-1. Applicants must show how any likely significant negative effects would be avoided, reduced, mitigated or compensated for, following the mitigation hierarchy.

2.8.6 NPS EN-5 (National Policy Statement for Electricity Networks Infrastructure) in conjunction with NPS EN-1 sets the policy context and provides the main guidance for the development and assessment of new network infrastructure. It outlines the Government's view that the development of overhead lines is not incompatible in principle with an applicants' statutory duty under Schedule 9 to the Electricity Act 1989 to have regard to visual and landscape amenity and to reasonably mitigate possible impacts. It sets out the government's position that overhead lines should be the strong starting presumption for electricity networks developments and that The Holford Rules (guidelines for the routing of new overhead lines) and the equivalent Horlock Rules for substation infrastructure, should be embodied in the applicants' proposals. The NPS goes on to recognise that this presumption is reversed (i.e assuming underground cable) when proposed developments will cross part of a nationally designated landscape (i.e. National Park, The Broads, or Areas of Outstanding Natural Beauty).

2.8.7 The NPS also sets out that the need to consider the case for undergrounding outside designated areas (2.9.23) and to consider, where there is the potential for significant adverse landscape and visual impacts (2.9.14), the need to have given due consideration to feasible alternatives to the overhead line. This could include, where appropriate, re-routing, underground or subsea cables, and the feasibility e.g. in cost, engineering or environmental terms of these but with decision making taking into account the costs and benefits of the alternatives.

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 and 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 NGET 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, NGET must resolve the capacity shortfall under the terms of its Transmission Licence. The standards against which NGET 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 onshore 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 NGET, 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 NGET assesses the adequacy of its transmission system in accordance with the method defined in the NETS Security and Quality of Supply Standard (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 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 212km 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 132kV connected gas fired power stations.

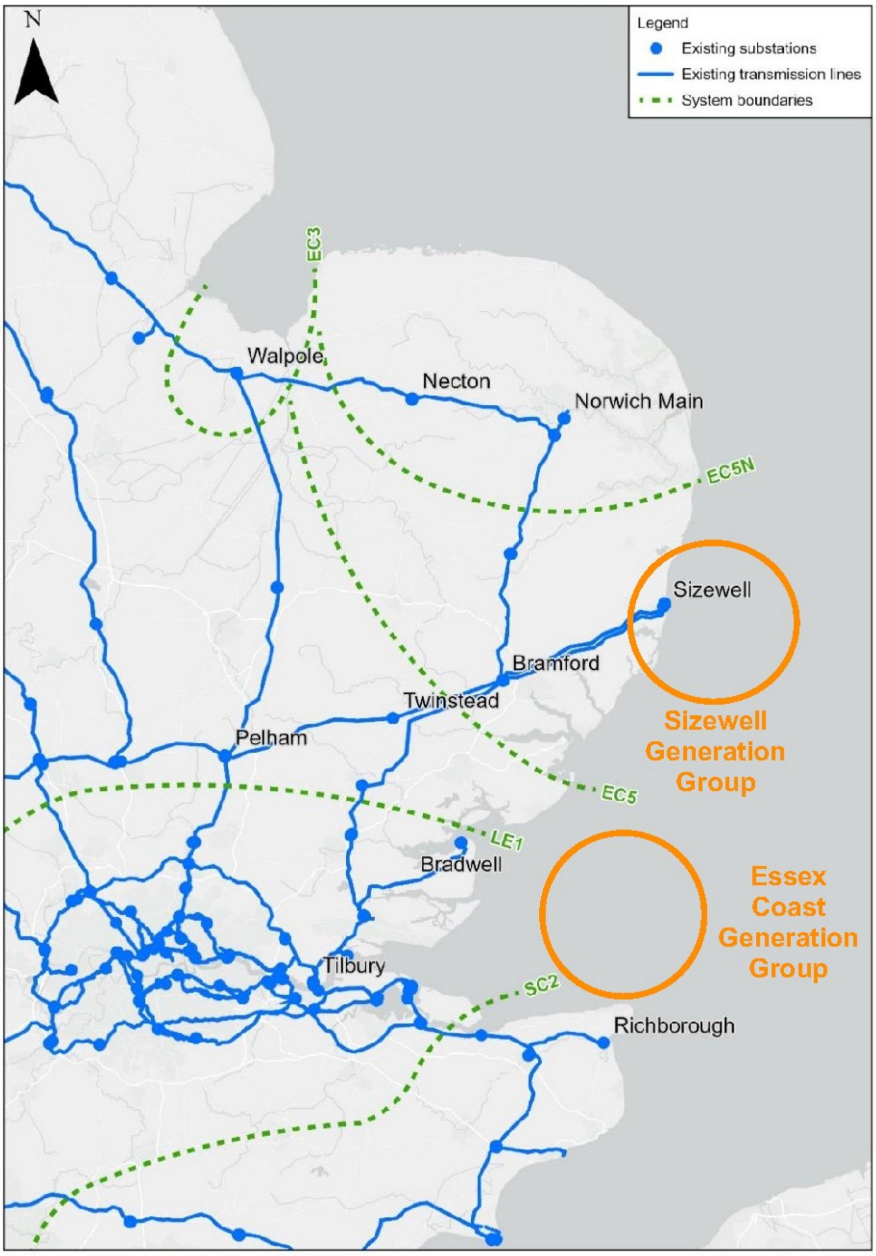
3.3.5 This generation capacity has recently been added to by several offshore windfarms with the existing generation totalling 7,687.4 MW of installed capacity. This is expected to grow substantially in coming years, as discussed further below.

3.3.6 The wider South East area, is made up of the 400kV and 275kV 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,

3.3.8 All diagrams within the report show the existing system following the completion of the Bramford to Twinstead project, which is included in the background considered for this projects Needs Case. The Bramford to Twinstead project is still subject to its own Development Consent Order which commenced in April 2023. However, should consent be granted, the Bramford to Twinstead project is proposed to be constructed and operational, ahead of the connection of any proposed infrastructure within this report.

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 50GW of offshore wind by 2030s as a key part of a strategy for secure, clean and affordable British energy for the long term.

3.4.2 NGET 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 NGET 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 22,907.6 MW of new generation (total generation of 30,595 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 with highlighted cells indicating change from the 2023 SOBR.

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 10/01/24
(#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	OCGT	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			
2024	Yare Power	Norwich 400kV	Energy Storage	49.5 MW	0.83	41.1 MW	*		
2024	Ashgreen Norwich	Norwich 400kV	Energy Storage	49.5 MW	0.83	41.1 MW	*		
2024	Pivoted Power (Norwich)	Norwich 400kV	Energy Storage	57.0 MW	0.83	47.3 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	LionLink (EuroLink)	Friston	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	East Anglia Three pt 2	Bramford 400kV	Wind	100.0 MW	0.7	70.0 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	Bramford BESS	Bramford 400kV	Energy Storage	400.0 MW	0.83	332.0 MW			
2029	Sizewell C Stage 1	Sizewell 400kV	Nuclear	1,670.0 MW	0.85	1,419.5 MW			#
2030	Spalding Extension part 2	Spalnding North	OCGT	500.0 MW	0.83	415.0 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			
2301	Equinor Stage 2	Norwich 400kV	Wind	231.0 MW	0.7	161.7 MW	*		
2031	Evolution Power Norfolk	Walpole 400kv	Energy Storage	860.0 MW	0.83	713.8 MW	*		
2031	Norwich Green Energy Centre	Norwich 400kV	Energy Storage	400.0 MW	0.83	332.0 MW	*		
2031	Norwich 100MW BESS	Norwich 400kV	Energy Storage	100.0 MW	0.83	83.0 MW	*		

Total 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)	17,115.3 MW		12,903.1 MW
Total Genration Existing and Contracted with No Fossil Fuel Contribution $ (MW)	25,215.5 MW		19,632.1 MW
Total Generation Existing and Contracted	30,595.0 MW		24,097.1 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
Minimum Transfer at ACS Peak with All Generation Impacting EC5N (Total Installed Generation* - Peak Demand*)			11,330.3 MW
Maximum Transfer at ACS Peak with All Generation Impacting EC5N (Total Generation* - Peak Demand*)			11,583.1 MW
Minimum Planned Transfer at ACS Peak with All Generation (Total Generation ($ excl fossil fuel) - Peak Demand)			17,865.1 MW
Maximum Planned Transfer at ACS Peak with All Generation (Total Generation - Peak Demand)			22,777.1 MW

3.6 Planned transfers

3.6.1 To assess SQSS compliance, NGET 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 NGET 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 5GW of gas turbine (CCGT and AGT) plant, 3 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 24,097.1 MW as compared to a total of 30,595 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 22,777.1 MW export (24,097.1 MW minus 1,767 MW).

3.6.12 The minimum forecast planned transfer with no contribution from fossil fuels in 2031 would be 17,865.1 MW export (19,632.1 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)
- 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. This table shows capacity across the EC5 boundary including the completion of the Bramford to Twinstead project.

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

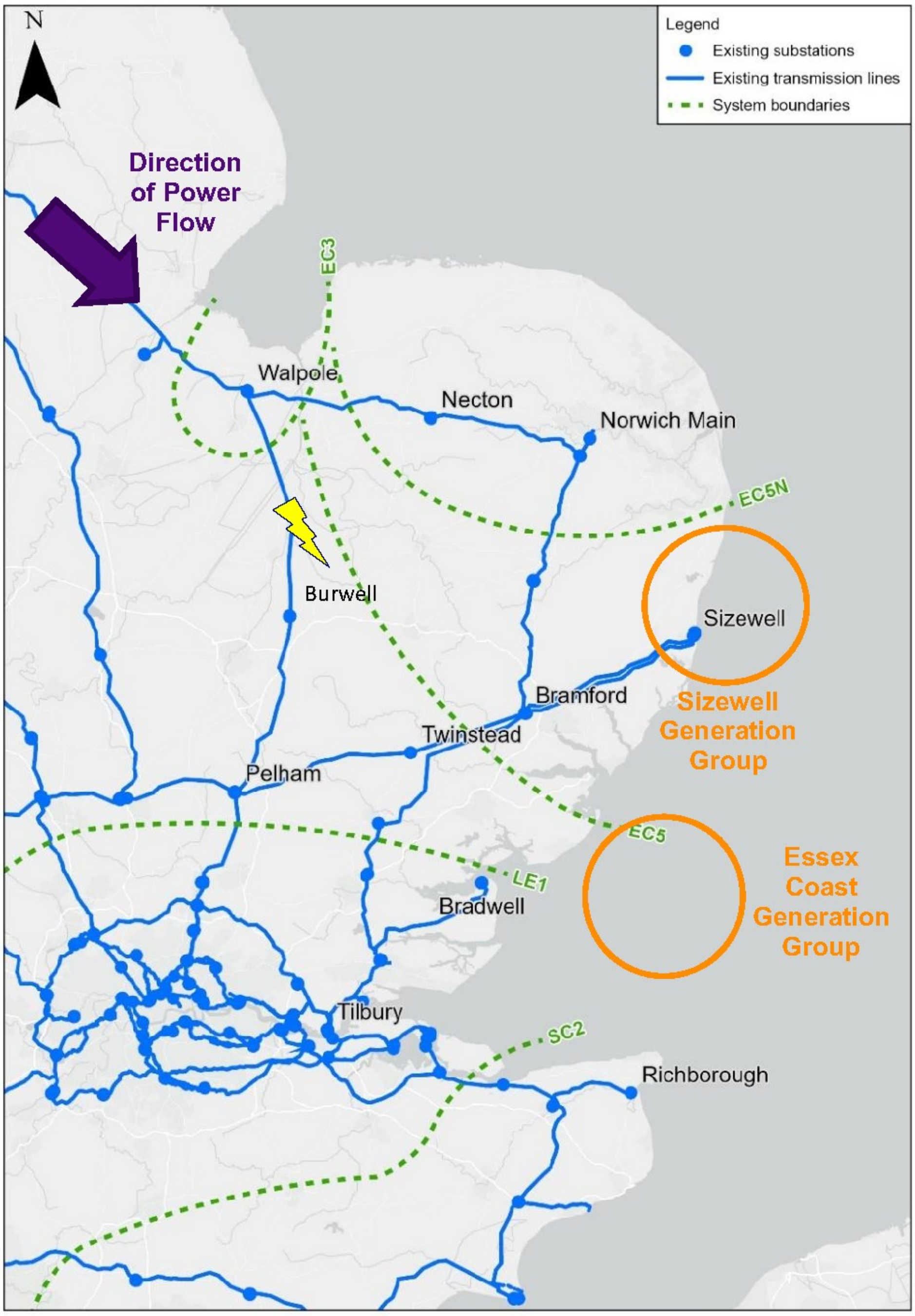


Table 3.3 – Planned Transfer requirements

Planned Transfer		Post Fault Capability by 2031	Planned Transfer Boundary Deficit
EC5N (Maximum)	11,583.1 MW	6,652 MW	-4,931 MW
EC5 (Maximum)	22,777.1 MW	13,552 MW	-9,225 MW
EC5N (Minimum*)	11,330.3 MW	6,652 MW	-4,678 MW
EC5 (Minimum)	17,865.1 MW	13,552 MW	-4,313 MW

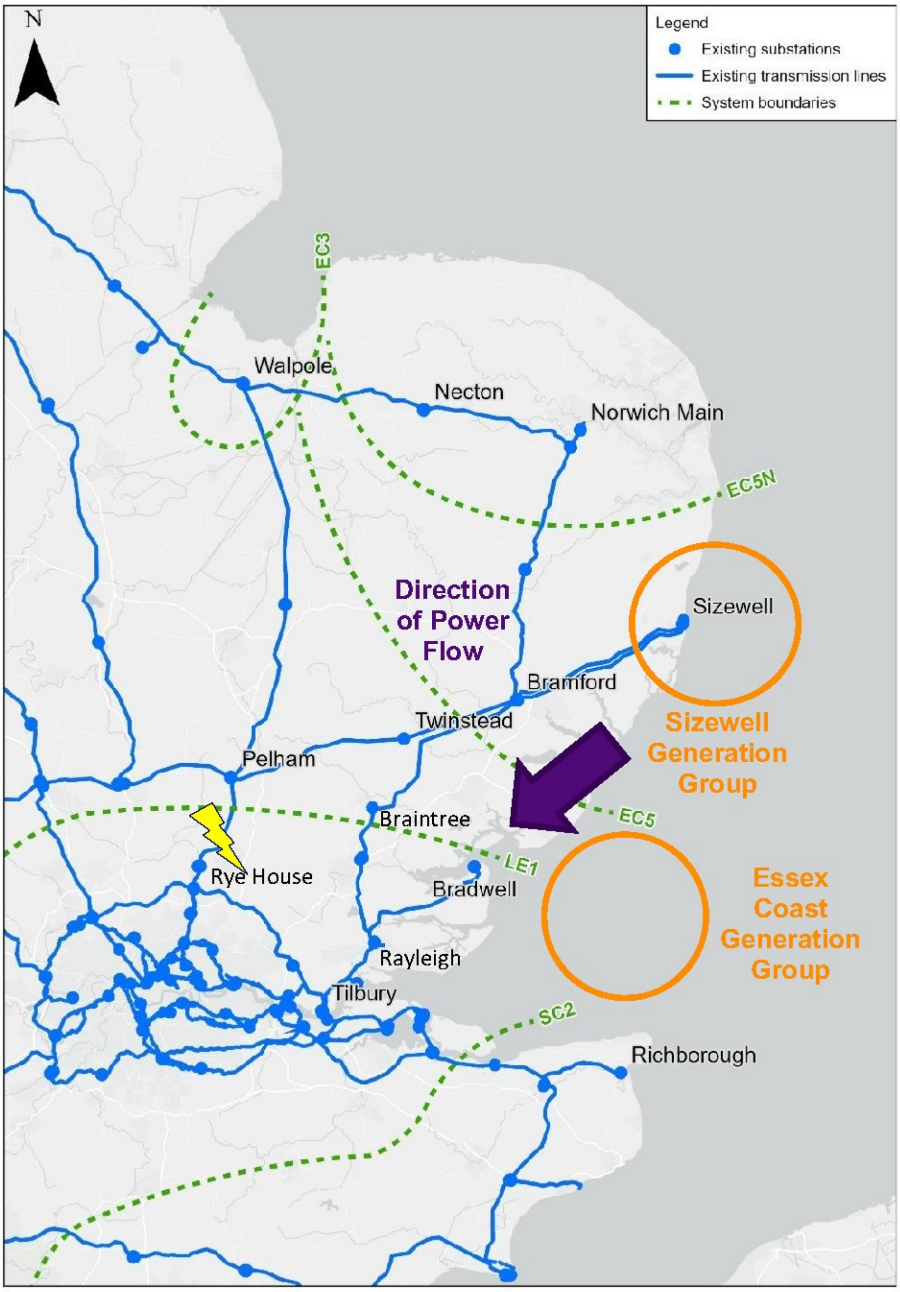
3.7.10 Table 3.3 above shows the maximum transfer required while fossil fuel gas fired power stations contribute to the system. The minimum levels assume gas fired power stations are not contributing.

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 across EC5 and EC5N in the range of 5,000 MW to 9,225 MW across and out of the East Anglia region. The SQSS requires us to design the network to accommodate the upper range value of 9,225 MW.

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.

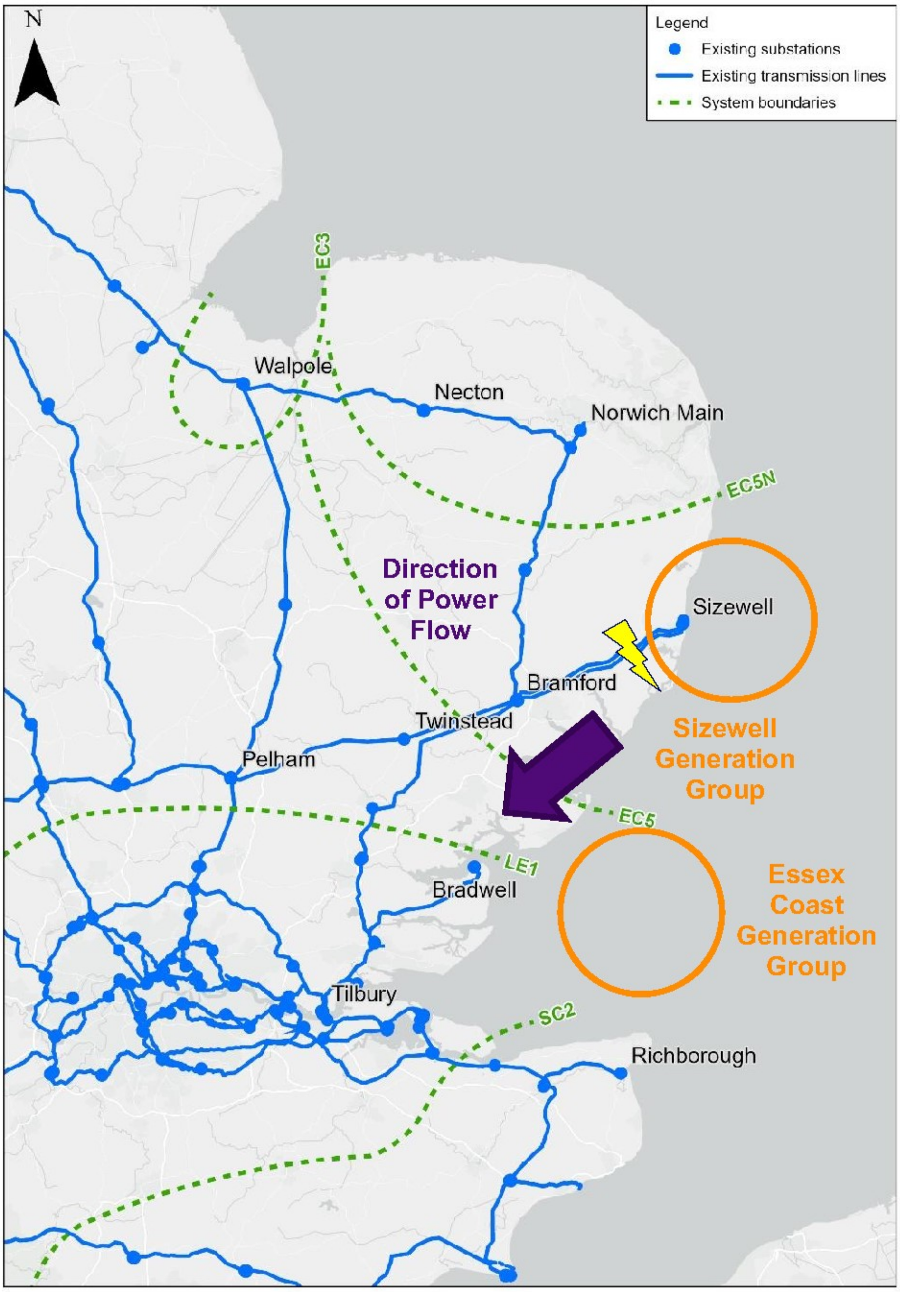
3.7.14 For the LE1 boundary the worst case fault is for the Pelham – Rye House double circuit as shown in Figure 3.3. During this fault the East Anglia generation will naturally seek to flow down the Bramford – Braintree – Rayleigh circuits causing them to overload above their maximum potential capability 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 2,856 MW [(1000MW + 1080MW)x0.7 + 1400MW] for the connection of North Falls, Five Estuaries and Tarchon as described as the Essex Coast Generation Group below increasing the deficit to -7476 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

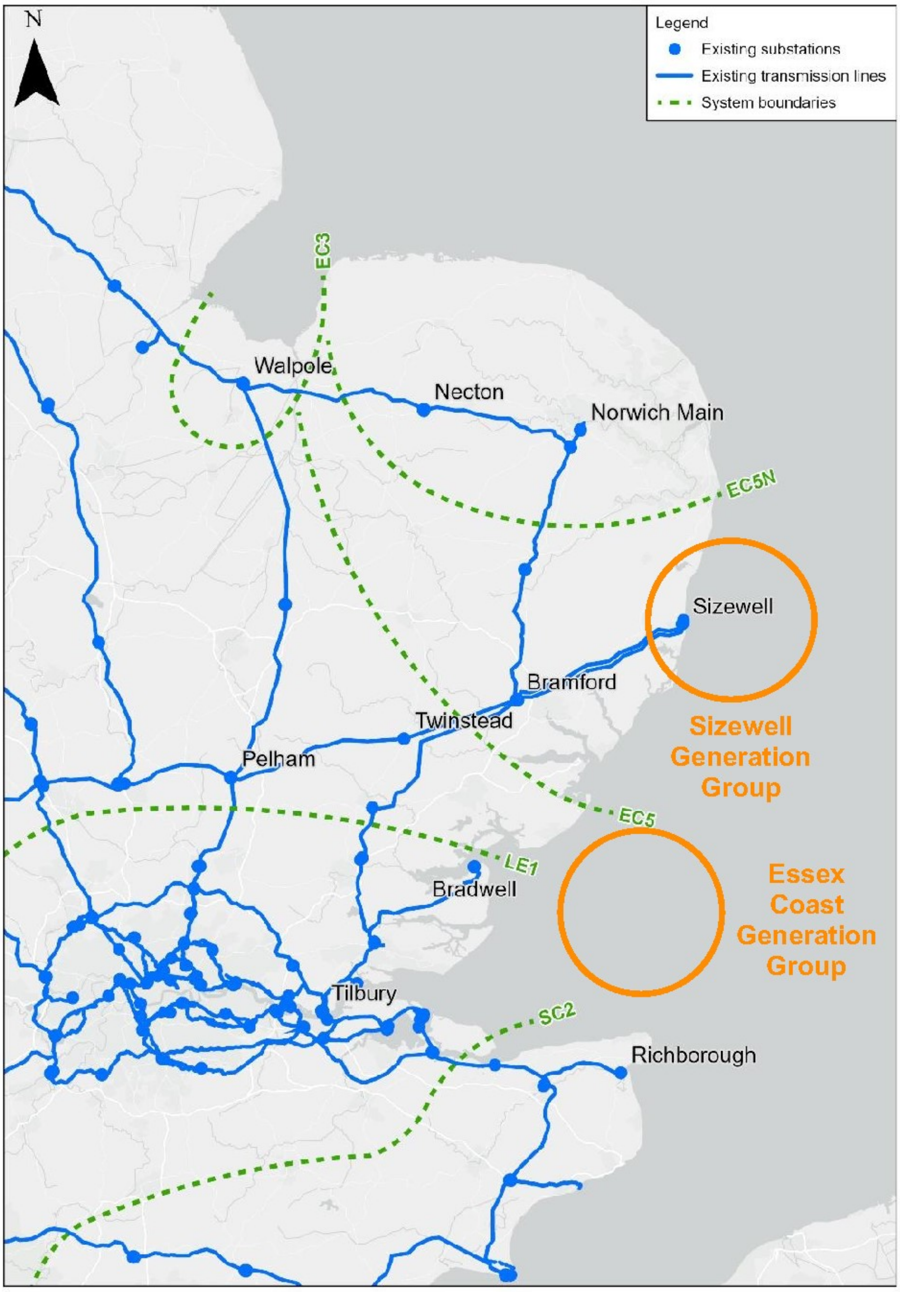
Figure 3.4 – Sizewell Generation Groups fault and impact



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. This leaves the remaining circuit with a maximum potential capability of 6,930 MW and generation transfer of 8,782.1 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 (1400 MW By 2030)
- North Falls offshore Windfarm (1000 MW by 2030)
- Five Estuaries Offshore Windfarm (1080 MW by 2030)

3.7.19 These connections are proposed to be made to the network at a location which can accommodate the combined 3480 MW of total generation. This requires a minimum of 3 transmission circuits to connect the generation to meet the requirements of the NETS SQSS.

SC2 Boundary

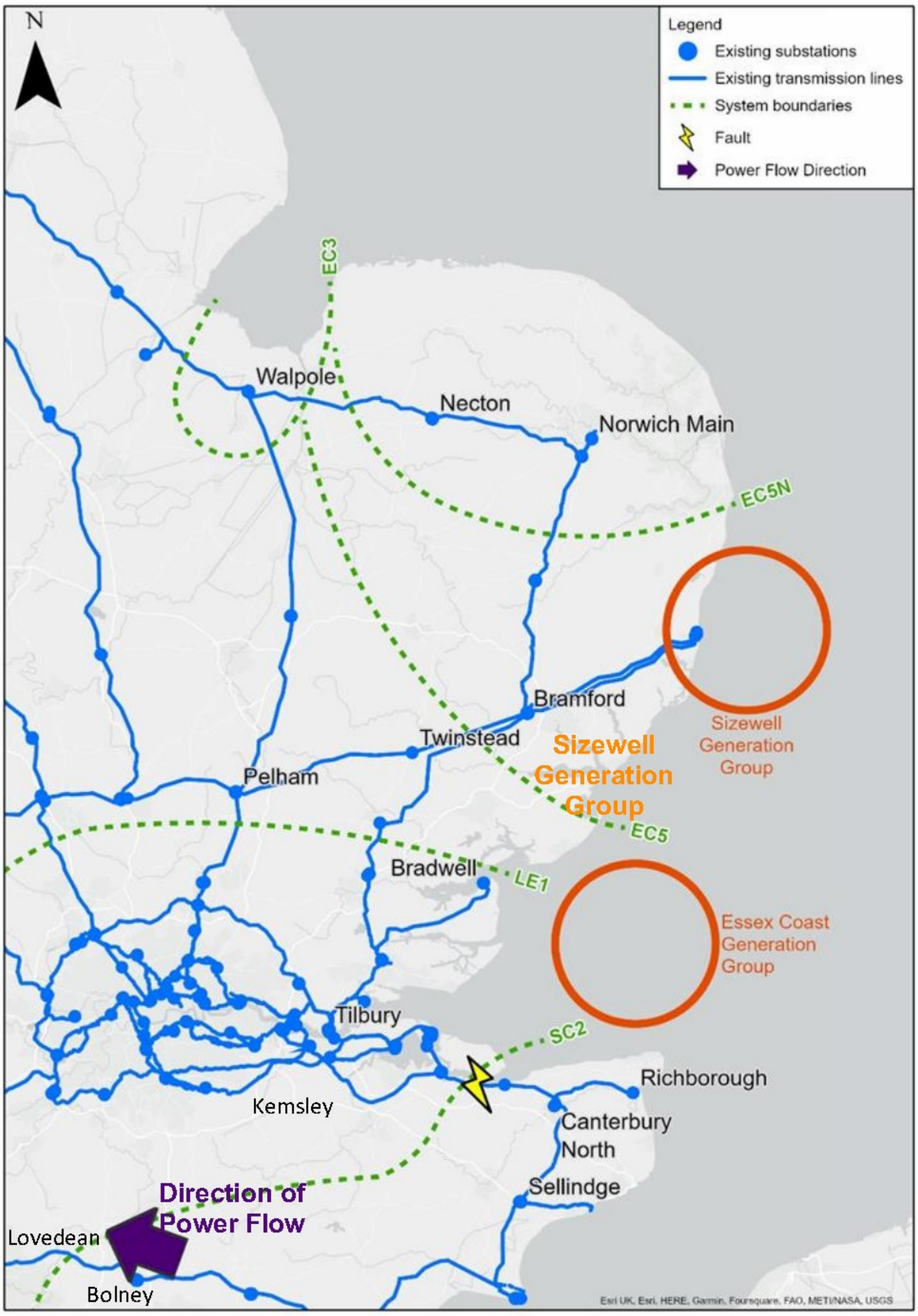
3.7.20 Table 3.4 shows the existing and contracted generation expected to connect in within the SC2 boundary of Kent by 2031. The existing SC2 boundary capability is 4500MW with the capability limited by thermal and voltage stability issues. The existing planned transfer from the SC2 boundary is 4,313MW,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

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 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 reinforcements:

- Provision of 9,225 MW of capacity across East Anglia EC5 Boundary and 4,931 MW of capacity across EC5N Boundary
- Provision of 7,476 MW of capacity across the LE1 Boundary
- Provision of 1,852 MW of capacity to the Sizewell Generation Group
- Provision of 3,480 MW of connection capacity from 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 backcheck, review and interactivity of options to resolve the need case set out above. NGET 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 failing to resolve the need would breach this requirement.

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 Backcheck and Review and how the process has been used to arrive at this list.

4.2 Corridor and Preliminary Routeing and Siting Study

4.2.1 In 2022, as part of the wider Network Planning Process, we carried out an initial assessment of the strategic options available to meet the need case set out in Section 3 above. This drew on the economic analysis of the ESO in the NOA process, and was presented in the April 2022 Corridor and Preliminary Routeing and Siting Study (CPRSS). This assessment identified 27 combinations of circuit options across a wide geographical area, later reduced to 23 (3 for west, 5 for north and 15 for east). For example, 'East 7' was a combination of AENC (Norwich – Bramford), ATNC (Bramford – Tilbury), SCD1 (Richborough – Sizewell) and TENC (Tilbury – Grain).

4.2.2 For each of these combinations of options we undertook an appraisal of deliverability, considered the system benefit that the reinforcement provided, and considered environmental and socio-economic factors. We considered whether in-principle environmental and socio-economic constraints with the potential to materially affect strategic options were present. We concluded that none were significant enough to materially influence strategic option selection. For example, whilst some relatively extensive areas of built development are present (Ipswich, Colchester etc) they can be avoided. In the case of national landscape designations (e.g. Dedham Vale; Suffolk Coast and Heaths; Surrey Hills; Kent Downs) we considered the relative location of these in combination with the potential to adopt alternative technology to OHL meant that none presented a barrier to development or indicated an option should not be progressed. Further detail of this exercise is given in the CPRSS.

4.3 NOA Cost Benefit Analysis

4.3.1 As part of the annual NOA cycle, each combination of options proceeded through the Cost Benefit Analysis (CBA) carried out by the ESO. This used the 'BID3' economic model, which is an economic dispatch optimisation model that simulates European energy markets, including demand, supply and infrastructure. It models the hourly generation of all power stations on the system, taking into account factors such as fuel prices, historical weather patterns and operational constraints. This allows avoided predicted constraint costs to be calculated for each option across the range of FES, based on their costs and delivery dates. The ESO's role, and both NOA and the FES, are discussed in Section 2 above.

4.3.2 Predicted constraint savings from each pathway were compared to the capital costs to assess whether 1) investment is economically optimal versus a ‘do nothing’ counterfactual (i.e. no capital costs are expended and constraint costs are incurred), and 2) if so, which option/pathway is economically optimal. Net Present Value (NPV) is calculated by deducting the present value of capital costs from the present value of predicted constraint costs for each option in each FES. Options were compared using a ‘Least Worst Regrets’ method, being ranked in order of the highest (i.e. worst) regret for each option, in comparison to all other options, across the four FES (i.e. if an option was the best in all FES, its Least Worst Regret would be 0).

4.3.3 Table 4.1 below shows the outcome of this analysis.

Table 4.1 – ESO Least Worst Regrets Analysis per Option in £m.

Reinforcement Strategy Option	Net Regret Cost by FES[6] (£m)				Worst Regret Cost (£m) ordered by least-worst regret
	CT	LW	SP	ST	
East	36	143	51	0	143
North 5	233	340	248	197	340
East 3	296	556	0	355	556
East 15	499	664	96	504	664
East 6	0	0	711	155	711
East 9	819	914	710	606	914
East 8	863	995	737	692	995
East 2	746	1,000	422	803	1,000
East 14	923	960	1,126	730	1,126
North 2	804	789	1,314	709	1,314
East 10	1,237	1,330	1,111	1,028	1,330
North 1	687	654	1,376	664	1,376
East 11	1,549	1,642	1,423	1,340	1,642
West 3	1,477	1,660	1,428	1,374	1,660
East 13	1,691	1,820	1,549	1,524	1,820
East 12	1,715	1,749	2,315	1,685	2,315
West 2	1,413	1,430	2,951	1,646	2,951
North 4	1,458	1,228	3,705	1,718	3,705
West 1	1,487	1,421	3,978	1,908	3,978
North 3	1,909	1,678	4,151	2,165	4,151
East 4	2,159	1,812	5,083	2,453	5,083
East 5	2,179	1,661	6,515	2,645	6,515
East 1	2,633	2,114	6,961	3,096	6,961

4.3.4 This economic assessment led to investment recommendations on whether individual reinforcements should proceed.

[6] The four Future Energy Scenarios as described in the 2020 versions of the Future Energy Scenarios. The scenarios are: Steady Progression (SP) - slowest credible decarbonisation; System Transformation (ST) – Hydrogen for heating; Consumer Transformation (CT) – Electrified heating; and, Leading the Way (LW) – Fastest credible decarbonisation.

4.3.5 The NOA analysis showed that combinations of options to the East and North were economically optimal, and that onshore overhead line options are preferred to offshore HVDC solutions.

4.3.6 The highest ranking option from an economical perspective, with an LWR of £143m, was the ‘East 7’ option. The schemes included in the East 7 option are shown below with their columns being project description and cost, NOA code, proposed option, circuit technology.

Table 4.2 – Strategic Combination Proposal East 7

East 7 Capex £2,189.75m As East 6 with enhanced export capacity from EC5	AENC	Norwich-Bramford	AC OHL (Onshore)
	ATNC	Bramford-Tilbury	AC OHL (Onshore)
	SCD1	Richborough-Sizewell	HVDC Cable (Offshore)
	TENC	Tilbury-Grain	AC OHL (Onshore)

4.3.7 The ‘East 6’ option is similar to East 7 with TENC excluded (i.e. AENC, ATNC and SCD1 only). This is the LWR option in two of the FES scenarios tested (Leading the Way and Consumer Transformation).

4.3.8 The second highest ranking option was ‘North 5’, incorporating ATNC, SCD1 and TENC (as per East 7), but with NPNC Necton-Pelham OHL replacing AENC.

4.3.9 Third highest ranked was ‘East 3’, incorporating ATNC and TENC (as per East 7), but with NTDC Necton-Tilbury HVDC Cable (Onshore) and CAKE Canterbury-Kemsley AC OHL.

4.3.10 The best performing option in the West (‘West 3’), combining ATNC and TENC with NCDC Norwich-East Claydon HVDC OHL (Onshore), IBNC Iver-West Weybridge-Bolney AC OHL (Onshore) had an LWR of £1,660m.

4.4 CPRSS conclusion

4.4.1 Taking all factors into account, the balanced conclusion across the range of scenarios was that the preferred reinforcement solution was provided by Option East 7. This solution combined offshore and onshore connections with three distinct elements: an offshore reinforcement between the south coast and East Anglia (SCD1); onshore reinforcement between Tilbury and Grain (TENC); and onshore reinforcement between Norwich and Tilbury (AENC/ATNC) via Bramford substation and a new East Anglia Connection Node substation.

4.5 NOA and HND recommendations

4.5.1 AENC, ATNC and SCD1 were subsequently given proceed signals in NOA 2021/22, and the July 2022 NOA Refresh also identified these reinforcements as ‘Holistic Network Design essential’ (HND essential) options. TENC does not have a proceed signal nor is it considered as required currently in the NOA Refresh and is therefore not being taken forward at this time. It does not form part of the Norwich to Tilbury project.

4.5.2 The analysis for the NOA and HND provided a solid foundation for identifying strategic options that are most viable and should be taken through further analysis.

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 Circuit 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 Circuit 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.
  - Capital and Circuit Lifetime Costs considers 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

5.1.7 Circuit Lifetime Costs, including circuit capital cost, cost of loses over 40 years and cost of operation over 40 years.

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

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

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

a) 400 kV AC Offshore cable

b) 525 kV HVDC Offshore cable and converter stations

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

5.1.11 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.

5.1.12 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.

5.1.13 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.

5.1.14 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).

5.1.15 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.

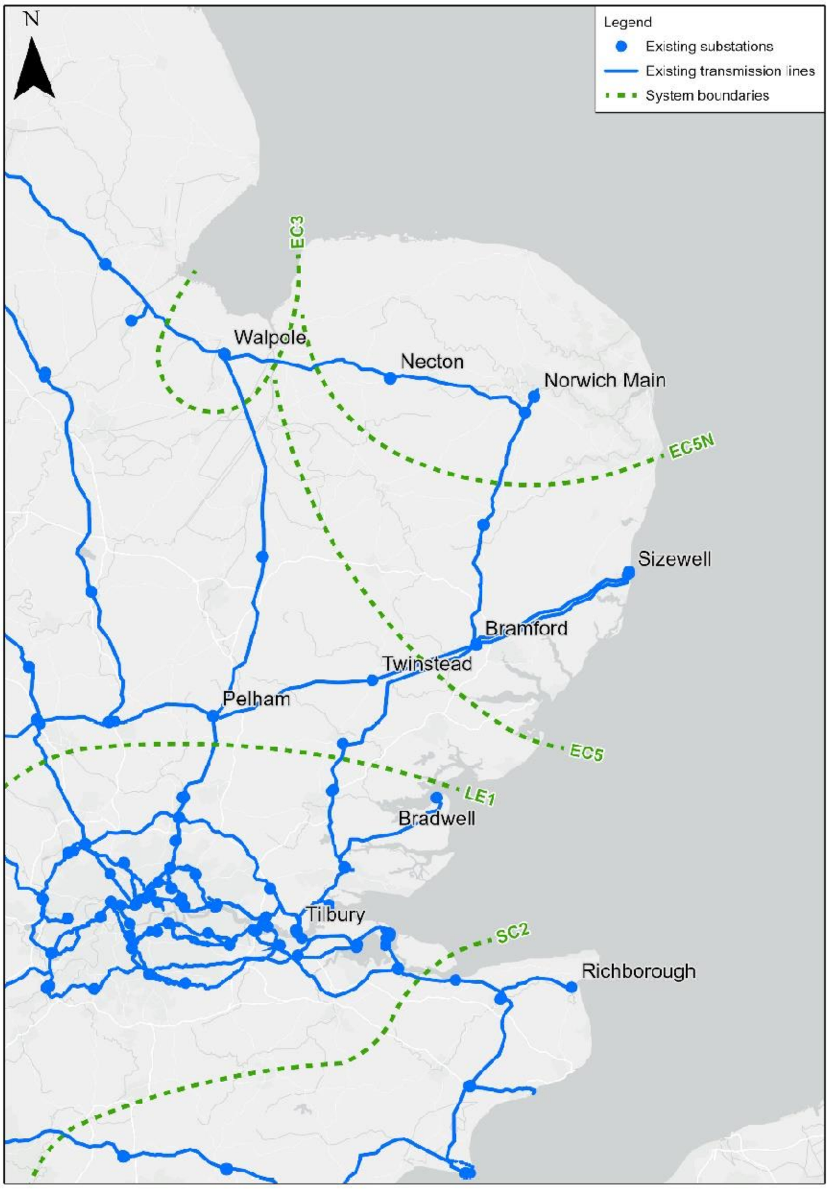
6. Strategic options overview

6.1 Introduction

6.1.1 As described in Section 3 above, the transmission system is in need of 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



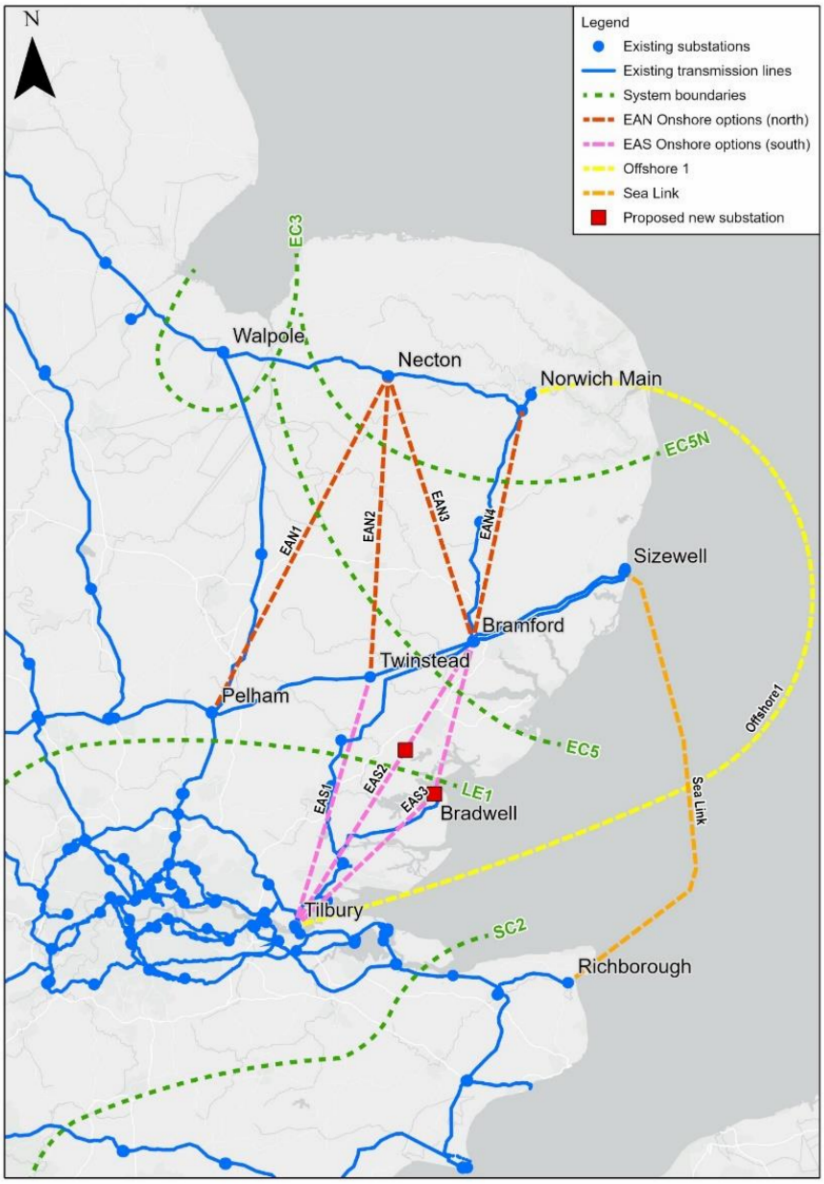
6.2 Connection options considered for detailed appraisal

6.2.1 In line with Our Approach to Consenting, this Strategic Options Backcheck and Review 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. Firstly, solutions to resolve capacity shortfalls across EC5 North, then across EC5 and LE1 combined. 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.

6.2.3 The report reviews each individual circuit option which can provide solutions to the North and East, including some additional options that did not form part of the previous analysis, as indicated below. Options in the West have not been carried forward to this stage in the process on the basis of the 'benefits' filter, given that the CPRSS and NOA CBA process showed these options to be significantly suboptimal, or because they offered no benefits over other options (e.g. a Norwich-Necton option offered no benefits over those northern options listed below).

Figure 6.2 – Connection options



6.2.4 The onshore options to resolve EC5 North boundary requirements are:

- EAN 1 – Necton to Pelham **115km** (NPNC in the previous analysis)
- EAN 2 – Necton to Twinstead **90km** (not included in the previous analysis)
- EAN 3 – Necton to Bramford **85km** (not included in the previous analysis)
- EAN 4 – Norwich Main to Bramford **80km** (AENC)

3.1.7 An offshore option, crossing boundaries EC5 North, ECN5 and LE1, is also considered:

- Norwich to Tilbury

6.2.5 As discussed earlier in the report, we are also currently evaluating detailed options for the full resolution of the need across boundaries SC2, LE1, EC5 and Sizewell generation group. As discussed in Section 4, a project know as Sea Link (NOA code SCD1) is also being taken forward to provide capacity across these boundaries. This project is subject to its own Options Report to determine the specific option to be taken forward. However, given the interactions with potential options in East Anglia, this report assesses the interaction of Sea Link (or its alternatives) with the proposed solution. This will demonstrate how all options considered in this report, in conjunction with the interactivity with Sea Link satisfy the overall need case outlined in Section 3.

6.2.6 The table below sets out the combinations that are required and which boundary or group condition they support.

Table 6.1 – Combination of Options required to meet need

<table>
<tr><th>Boundary or Group</th><th colspan="6">Onshore Options</th><th>Offshore</th></tr>
<tr><td>EC5N & EC3</td><td>EAN 1</td><td colspan="2">EAN 2</td><td colspan="2">EAN 3</td><td>EAN 4</td><td rowspan="2">Offshore 1</td></tr>
<tr><td>EC5 & LE1</td><td colspan="2">EAS 1</td><td colspan="2">EAS 2</td><td colspan="2">EAS 3</td></tr>
<tr><td>SC2, EC5, LE1 & Sizewell</td><td colspan="7">SCD1 Sea Link (or alternative)</td></tr>
</table>

6.2.7 Any combination of North, South and SCD1 Sea Link circuits can be used to meet onshore need. Offshore 1 and SCD1 Sea Link required to meet offshore need. This means that Sea Link is required in all cases.

6.3 Updated costs

6.3.1 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 full backcheck and review of all options supersedes any information provided prior to April 2023.

6.3.2 We have previously provided cost information for comparison between onshore and offshore technologies, most recently to the Offshore Electricity Grid Task Force (OffSET). All previous costs were given for circuits only. This analysis specifically identified that offshore connection costs of at least £500m had not been included in the costs. The cost of options included in this report have been updated to ensure that both the onshore and offshore substations required to make all connections are included within the option cost. This enables the reader to fully understand the comparable option cost, without having to adjust any numbers manually.

6.4 Study areas

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

6.5 East Atlantic Flyway Nomination as WHS

6.5.1 National Grid has noted the UK government's nomination, of various areas of the east coast as part of the East Atlantic Flyway UNESCO World Heritage Site (WHS). This would bring together a coastal network of wetlands and protected spaces that include Marine Protected Areas, Ramsar Sites, Special Protection Areas and Special Areas of Conservation.

6.5.2 National Grid's current assumption is that, if the nomination is successful, then any future management plan, would comprise similar protections to those applying to these designated sites as at present. The existing designations and protections were considered as part of routeing and siting as set out in the CPRSS, and as such it is not considered that the potential WHS designation is inconsistent with or would be undermined by the proposals. National Grid will update its position as further information becomes available.

6.5.3 On this basis, the previous assessments considering the current protections lead to the same conclusion as if the East Atlantic Flyway WHS designation was confirmed.

6.6 Strategic Options

6.6.1 The following sections of this report deal with each strategic option individually detailing environmental, socio-economic, technical and cost appraisals.

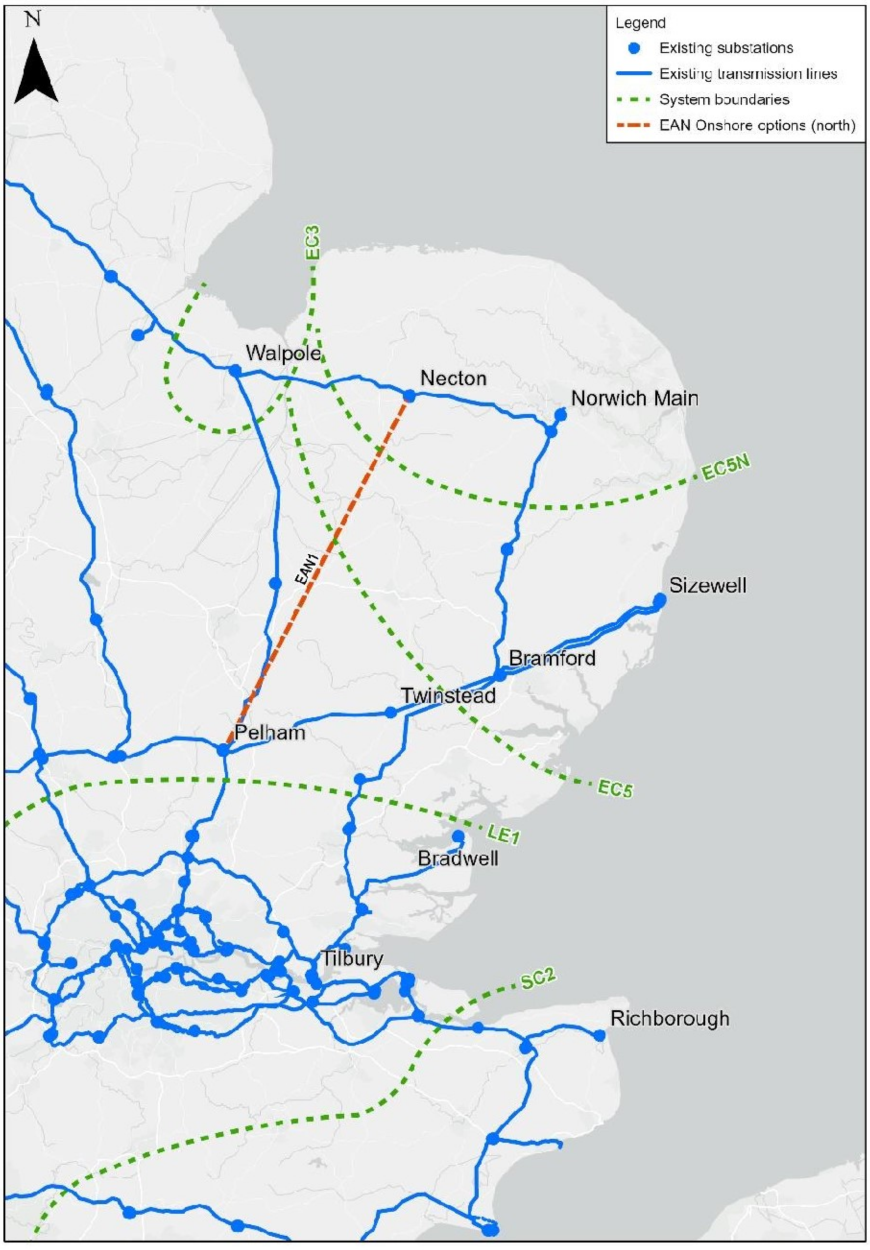
7. EAN1 – Necton to Pelham

7.1 Introduction

7.1.1 Strategic option EAN 1 involves a new 400kV transmission connection between the existing Necton substation and the existing Pelham substation, a distance of approximately 115 km. Shown in Figure 7.1.

7.1.2 The location of Pelham means that, to convey power further south from this location, further reinforcement of southern circuits would be required, including the need to reinforce Twinstead substation should this option be taken forward.

Figure 7.1 – Option EAN 1 Necton to Pelham



7.2 Environmental appraisal

Landscape and visual

7.2.1 Much of the study area comprises constraints to an AC OHL, some of which can be addressed by conventional approaches e.g. routeing.

7.2.2 Whilst it should be possible with this option to avoid some potential adverse effects on the landscape and visual amenity, it is likely some significant residual effects are possible, for residents along affected settlement edges and scattered properties, and for Registered Parks and Gardens due to the number present within the study area.

7.2.3 This option is moderately to heavily constrained in relation to landscape and visual considerations, with a number of opportunities to avoid constraints and for mitigation through more detailed assessment, siting and installation which would prevent and/or reduce potential for significant landscape and visual effects, but a number of adverse effects may remain.

7.2.4 There may be opportunity for paralleling existing OHLs to reduce the spread of infrastructure in the south of the study area. Due to the number of settlements and Registered Parks and Gardens it may be challenging to find a route which achieves a parallel alignment. An additional line may result in increased ‘wirescape’ on approach to Necton and Pelham. Four existing 400kV OHLs converge on Pelham Substation.

Historic environment

7.2.5 Scheduled monuments are distributed throughout the study area and include sites dating from the prehistoric period onwards. While examples of scheduled monuments have been recorded throughout the study area, there is a significant number in the southern half of the study area including many linear scheduled monuments. Many of these are ditches or dykes, and at least five straddle the A505 and the A41 between Newmarket and Royston, although another long dyke lies on the western side of Brandon in the northern half of the study area.

7.2.6 Although ‘non-linear’ scheduled monuments are located throughout the study area, concentrations have been identified in the northern limits and the southern half of the study area, with relatively few around the South Levels and the eastern side of the Bedford Levels. It is assumed this lack of scheduled monuments is linked to the wet low-laying nature of this landscape which has made settlement activity difficult at various times during the last 10,000 years.

7.2.7 Listed buildings have been recorded throughout the study area, with the vast majority being Grade II listed, although a relatively large number of Grade I and II* buildings have been recorded due to the size of the study area. The focus of these are the settlements scattered throughout the study area, although Grade II listed buildings have also been recorded throughout the landscape.

7.2.8 A number of registered parks and gardens have also been recorded throughout the study area, although, as with the scheduled monuments, these are focused in the southern half and northern limits of the study area. Specific concentrations include two Grade I listed landscapes in the southern limits of the study area, as well as several Grade II and II* listed landscapes around Newmarket, Cambridge, and Saffron Walden.

7.2.9 Although a review of non-designated assets was not undertaken as part of this appraisal, the Defence of Britain data set was examined, and a relatively large number of assets were recorded in the study area. These include a large concentration of defensive structures running from Cambridge to Saffron Walden, with another focus between Ely/Littleport and Bury St. Edmunds. A third concertation has been identified in the north between March and Downham Market, and all of these clusters appear to have formed parts of 'Stop Lines' constructed during the Second World War.

7.2.10 It is likely that designated assets, such as scheduled monuments and listed buildings would 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.

7.2.11 Whilst designated assets are likely to be avoidable when considered in isolation to other topic constraints, due to the linear nature of a number of the designated scheduled monuments avoidance is likely to introduce multiple angles to an AC OHL route.

7.2.12 There is the potential for significant impacts on the setting, with high value designated assets identified throughout the study area. This includes the parks and gardens in the southern and northern sections of the study area, as well as the scheduled monuments and listed buildings throughout the study area. The National Trust holding at Wicken Fen should also be avoided if possible.

7.2.13 Mitigation would 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.

Ecology

7.2.14 Statutory designated sites for nature conservation are likely to be avoidable within this study area.

7.2.15 A principal consideration is the Breckland Special Protection Area (SPA)/Special Area of Conservation (SAC)/Site of Special Scientific Interest (SSSI) complex which is located within the northwest of the study area. Whilst these sites are avoidable there is the potential for impacts on the interest features associated with both habitats and species for which the sites are designated both during construction and operation. Avoidance of the Breckland network of sites would also require a longer AC OHL due to the location of this complex to the south of Necton.

7.2.16 Routeing would need to consider bird flight paths associated with the Breckland network of sites. Recognised mitigation measures for AC OHL impacts to bird assemblages would need to be used wherever appropriate. Mitigation for impacts of AC OHL connections on bird populations are available, such as bird diverters, 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 sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g., insulated components, greater air space between lines).

7.2.17 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitats and Species Regulations 2017.

7.2.18 Whilst designated sites are likely to be avoidable, to avoid the linear designated sites such as Roman Road, Fleam Dyke, Devil's Dyke) it is likely that this could introduce multiple angles into an AC OHL route.

Physical environment

7.2.19 Any AC OAC route between Necton and Pelham substations would have to cross over several unavoidable watercourses and that of its floodplains. Given the extent of Flood Zones 2 & 3, across the entire study area, it is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

7.2.20 Crossings of main rivers, flood zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable.

7.2.21 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

7.3 Socio-economic appraisal

Settlements and populations

7.3.1 There are fourteen main settlements within the study area and smaller settlements scattered throughout.

7.3.2 The south of the study area is more densely populated with multiple urban settlements which could impact on the ability to route an AC OHL in this area without multiple angles or near to settlements.

7.3.3 Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction associated with noise, air quality and construction traffic. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal.

Tourism and recreation

7.3.4 There are a number of National Cycle Networks (NCN) routes within this study area, one section of the Peddar's Way and Norfolk Coast Path National Trail runs through the study area and there are five Country Parks within the study area, the three largest are located around Cambridge. A National Trust holding at Wicken Fen is also present within this study area and should be avoided.

7.3.5 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction, however this is likely to be the case with any option, and effects would be temporary. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN, and these effects would be permanent.

7.3.6 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route and national trails should part of a cycle route or national trail be closed during construction.

Land use

7.3.7 Known BMV land (Grade 1 and 2) is present in the study area. Grade 1 BMV land is concentrated in the northwest and could be avoided should routeing extend close to the eastern border. Grade 2 BMV land is scattered throughout this study area and is considered unavoidable. Loss of BMV likely to be limited for the AC OHL route.

7.3.8 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints, but this is unlikely to be significant. Other land uses are likely to be avoidable.

7.3.9 Standard best practice guidelines should be followed to reinstate agricultural land following construction.

7.3.10 Golf courses, Countryside Rights of Way Access Land Parcels and Forest and Country Parks should be avoided by routeing where possible.

Infrastructure

7.3.11 The M11 Motorway is located in the southeast, although avoidable it is considered likely the M11 would need to be crossed. There are five trunk roads within this study area. The A47 is located in the north and would not be affected. Four trunk roads are located in the south including the A1, A11, A14 and A428. The A14 extends across the study area from east to west, this would be unavoidable. It is considered the M11 and A11 would need to be crossed within this study area.

7.3.12 There are several railway lines running through the study area. At least three railway lines would be unavoidable within this option.

7.3.13 Port of King's Lynn is located in the northwest corner. There are 22 airports including Biggleswade Airfield, Cambridge International Airport, Chatteris Airfield, Duxford Airfield, Lakenheath Airfield, Little Grandsden Airfield, RAF Mildenhall, Stansted Airport, The Egerton-Smith Centre, Top Farm Airfield and 12 unnamed airports. With careful routeing ports and airports are avoidable.

7.3.14 Where crossings of other infrastructure is required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

7.3.15 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.

7.3.16 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

7.3.17 Routeing of a new AC OHL would have to take account of the 22 airports, aerodromes and MOD airport (including any associated low flying zone) 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.

7.4 Technical scope and costs

7.4.1 Technical analysis of option EAN 1 is as follows:

- This option to connect a 115km circuit between Necton and Pelham, takes energy west to Pelham located North of London.
- Due to the location of Pelham to convey power further south from this location will require further reinforcement of southern circuits including the need to reinforce Twinstead substation should this option be taken forward.

7.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

7.4.3 Option EAN 1 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, six overall. This is to come close to matching the AC hi-capacity circuits of 6930 MVA.
  - The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end included in brackets () in the table.
- **Substation works**
  - Extension to Necton 400kV Substation by 2 bays to accommodate new circuits.
  - Extension to Pelham 400kV Substation by 2 bays to accommodate new circuits.

Table 7.1 – below sets out the capital costs for option EAN 1 considering substation works and each technology option.

Item	Need	EAN 1 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£36.8m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 115 km	New Circuit across EC5 North	£457.7m	£4,959.1m	£4974.9m	£2,669.2m (£1,799.5m)
Total Capital Cost		**£494.5m**	**£4,995.9m**	**£5,011.7m**	**£2,706.0m (£1,836.3m)**

7.4.4 Table 7.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 – EAN 1 Circuit Lifetime Cost Summary

Land Based option	EAN 1 AC OHL	EAN 1 AC Underground Cable	EAN 1 AC GIL	EAN 1 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£457.7m	£4,959.1m	£4,974.9m	£2669.2m (£1,779.5m)
NPV of cost of losses over 40 years	£322.6m	£246.9m	£149.8m	£471.2m (314.1m)
NPV of operation & maintenance costs over 40 years	£6.7m	£23.4m	£6.8m	£172.4m (£114.9m)
Circuit Lifetime Cost of new circuits	**£787m**	**£5,229m**	**£5,131m**	**£3,313m (£2,209m)**

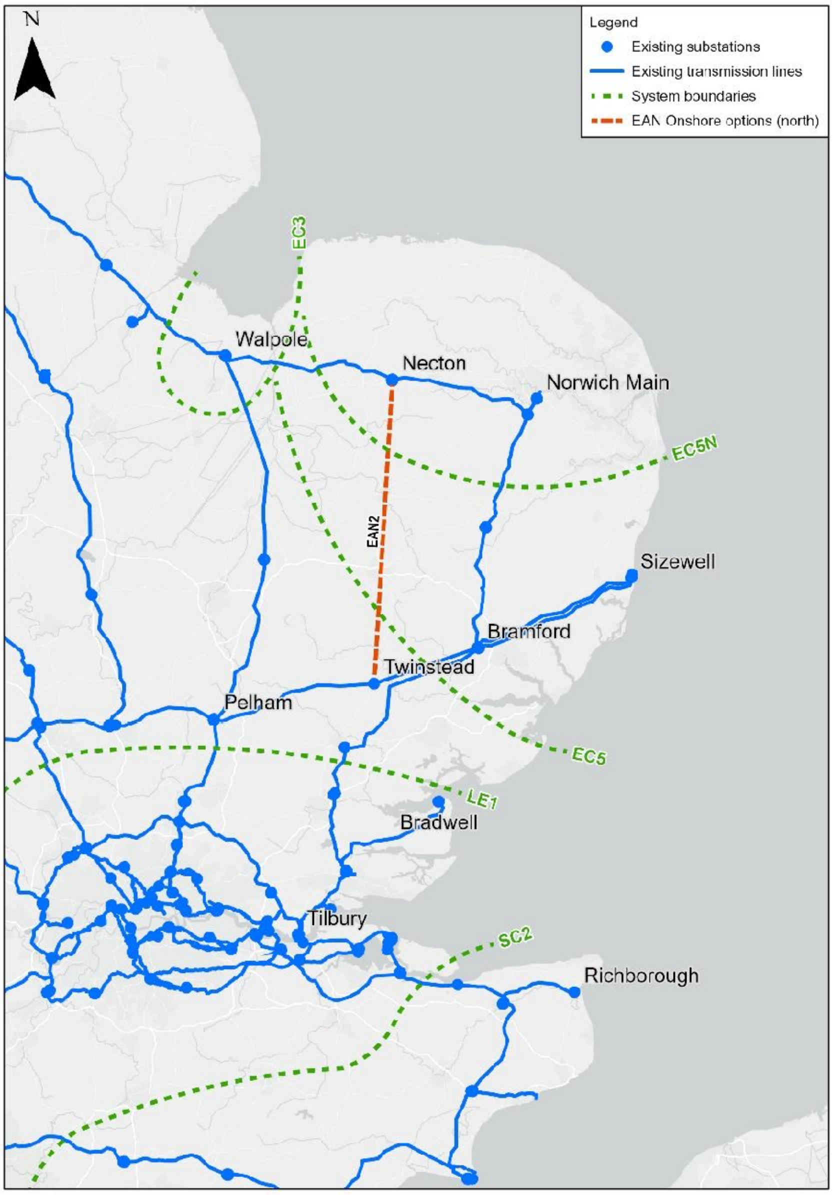
8. EAN2 – Necton to Twinstead

8.1 Introduction

8.1.1 Strategic option (SO) EAN 2 involves a new 400kV transmission connection between existing Necton substation and a New Twinstead substation, a distance of approximately 90 km. shown in Figure 8.1.

8.1.2 Currently the proposed Twinstead substation is a small connection of demand connection to the local Distribution Network Operator. This site is not sufficient for the connection of new circuits, so a new larger site would need to be established to facilitate the connection of multiple circuits, the number of which would depend upon the combination of options selected to satisfy the need case set out in this report.

Figure 8.1 – Option EAN 2 Necton to Twinstead



8.2 Environmental appraisal

Landscape and visual

8.2.1 If the study area comprises relatively limited constraints to an AC OHL which can be addressed by conventional approaches. However, the central part of the study area has a cluster of sensitive receptors, and it may be challenging to find a direct route without additional mitigation such as undergrounding. Whilst it should be possible with this option to avoid a good proportion of potential other adverse effects on the landscape and visual amenity, some significant residual effects are possible for residents along affected settlement edges and scattered properties.

8.2.2 As with all the options, route alignment/siting would be required to mitigate potential effects on landscape and visual receptors. The larger settlements to the east and west of the study area could be avoided through sensitive routeing. Sensitive routeing at the crossing of the Peddar's Way and Norfolk Coast Path could help to reduce the potential effect on users of the National Trail. The cluster of Registered Park and Gardens (RPGs) and a Country Park centrally in the study area and higher concentration of RPGs may require additional mitigation such as undergrounding.

8.2.3 This option is moderately constrained, with several opportunities to avoid constraints and for mitigation through more detailed assessment, siting and installation which would reduce potential for significant landscape and visual effects, but several adverse effects may remain.

8.2.4 This option would not offer any close parallel opportunities.

Historic environment

8.2.5 Designated sites are distributed throughout the study area, although the majority of listed buildings are within settlements such as Thetford, Bury St Edmunds and Ixworth. Scheduled monuments are located throughout the study area, although large clusters have been identified in the northern part of the study area with large sites including Woodcock Hall Roman town and Roudham deserted medieval village. Other clusters have been recorded near Thetford.

8.2.6 Like the other high value assets, RPGs are located throughout the study area, although large key sites include Shadwell Park and Euston Park near Thetford, and Kentwell Hall and Melford Hall near Sudbury in the south.

8.2.7 Many military defences have also been recorded, including large concentrations running from north to south through the southern half of the study area from Bury St Edmunds to Sudbury, with a second cluster from Thetford to Ixworth. These appear to represent parts of “Stop Lines” constructed during the Second World War. Other non-designated assets have not been considered as part of this assessment.

8.2.8 It is likely that designated assets, such as scheduled monuments and listed buildings would be avoidable. 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.

8.2.9 There is the potential for significant impacts on the setting of high value designated assets identified throughout the study area.

8.2.10 Mitigation would 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.

Ecology

8.2.11 Statutory designated sites for nature conservation are likely to be avoidable within this study area.

8.2.12 A principal consideration is the Breckland SPA/SAC/SSSI complex which is located within the western half of the study area. Whilst these sites are likely to be avoidable this would require an increased length of AC OHL in order to connect at Necton so as to avoid the sites by routeing to the east.

8.2.13 Routeing would need to consider bird flight paths associated with the Breckland network of sites. Recognised mitigation measures for AC OHL impacts to bird assemblages would need to be used wherever appropriate. Mitigation for impacts of AC OHL connections on bird populations are available, such as bird diverters, 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 sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g., insulated components, greater air space between lines).

8.2.14 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitats and Species Regulations 2017.

Physical environment

8.2.15 Any AC OAC route between Necton and Twinstead would have to cross over several unavoidable watercourses and associated flood zones. Given the extent of Flood Zones 2 & 3, across the entire study area, it is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

8.2.16 Crossings of main rivers, Flood Zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable.

8.2.17 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

8.3 Socio-economic appraisal

Settlements and populations

8.3.1 There are five main settlements within this study area and smaller settlements scattered throughout. Population density increases towards the south.

8.3.2 The south of the study area is more densely populated with multiple settlements which could impact on the ability to route an AC OHL in this area without multiple angles.

8.3.3 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 adverse visual effects which are set out in the landscape and visual appraisal.

8.3.4 Standard best practice guidelines should be followed to reduce potential noise and air quality effects during construction. Control measures should be put in place to potential impacts associated with construction traffic.

Tourism and recreation

8.3.5 There are a number of NCNs routes and unnamed routes within this study area. It is considered at least four NCN's are unavoidable. One section of the Peddar's Way and Norfolk Coast Path National Trail runs through the study area. There are three Country Parks within the study area. Knettishall Heath and Nowton Park lie centrally, with Great Conard to the south of the study area.

8.3.6 There is the potential for temporary adverse effects associated with severance should cycle routes or national trails need to be temporarily closed during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN and national trail.

8.3.7 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route and national trails should part of a cycle route or national trail be closed during construction.

Land use

8.3.8 There is no Grade 1 BMV land within this study area. Grade 2 BMV land is located in fragmented sections throughout the study area, although is more prominent in the south, particularly along the western and southern border. Grade 3 BMV agricultural land is the most prominent land type classification. Loss of BMV likely to be limited for the OHL route.

8.3.9 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints but this is unlikely to be significant. Other land uses are likely to be avoidable.

8.3.10 Standard best practice guidelines should be followed to reinstate agricultural land following construction.

8.3.11 Golf courses, Countryside Rights of Way Access Land Parcels and Forest and Country Parks should be avoided by routeing where possible.

Infrastructure

8.3.12 There are no motorways within this study area. Three trunk roads are located within this study area. The A47 is located in the northwestern corner extending north of Necton substation and is therefore considered avoidable. The A11 extends across the middle of the study in the north between Thetford in the west and Attleborough in the east. The A14 also extends across the middle of the study area in the south between Bury St Edmunds in the west and Haughley in the east. The A14 and A11 are unavoidable within this this study area.

8.3.13 There are a number of railway lines running through the study area. There are four railway lines within this study area, one extends diagonally across the northeast corner between Dereham and Thuxton, one is located in the south and connects into Sudbury from Bures at the southern border and two railway lines extend across the middle of the study area from west to east (between Thetford and Attleborough and between Bury St Edmunds and Haughley). It is considered at least two railway lines are unavoidable.

8.3.14 There are four aerodromes located within this study area. Honington Airfield is located in the north. Wattisham Airfield and two unnamed airfields (located at Felsham and Bury St Edmunds) are located in the south. There are no ports and harbours within this study area. It is considered Woodbridge Airfield is easily avoidable.

8.3.15 Where crossings of other infrastructure is required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

8.3.16 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.

8.3.17 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

8.3.18 Routeing of a new AC OHL would have to take account of the four 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.

8.4 Technical scope and costs

8.4.1 Technical analysis of option EAN 2 is as follows:

- This option to connect a 90km circuit between Necton and the proposed new substation at Twinstead, takes energy west to location of a new substation at Twinstead
- Currently the proposed Twinstead Substation is a small connection of demand connection to the local Distribution Network Operator. This site is not sufficient for the connection of new circuits, so a new larger site would need to be established to facilitate the connection of multiple circuits, the number of which will depend upon the combination of options selected to satisfy the needs case set out in this report.

8.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

8.4.3 Option EAN 2 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, six overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
  - The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, four overall, this cost is included in brackets () in the table.
- **Substation works**
  - Extension to Necton 400kV Substation by 2 bays to accommodate new circuits.
  - New Twinstead 400kV substation able to accommodate 14 bays (22 bays if option chosen in combination with non Twinstead EAS option)

Table 8.1 – below sets out the capital costs for option EAN 2 considering substation works and each technology option.

Item	Need	EAN 2 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£136.0m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 90 km	New Circuit across EC5 North	£358.2m	£3,873.6m	£3,893.4m	£2,437.4m (£1,625.0m)
Total Capital Cost		**£494.2m**	**£4,009.6m**	**£4,029.4m**	**£2,573.4m (£1,761.0m)**

8.4.4 Table 8.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 – EAN 2 Circuit Lifetime Cost Summary

Land Based option	EAN 2 AC OHL	EAN 2 AC Cable	EAN 2 AC GIL	EAN 2 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£358.2m	£3,873.6m	£3,893.4m	£2,437.4m (£1,625.0m)
NPV of cost of losses over 40 years	£252.5m	£188.4m	£117.2m	£471.2m (£314.1m)
NPV of operation & maintenance costs over 40 years	£5.3m	£18.2m	£5.3m	£172.2m (£114.8m)
Circuit Lifetime Cost of new circuits	**£616m**	**£4,080m**	**£4,016m**	**£3,081m (£2,054m)**

8.4.5 The environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAN 2, 90 km connection between a Necton and New Twinstead 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

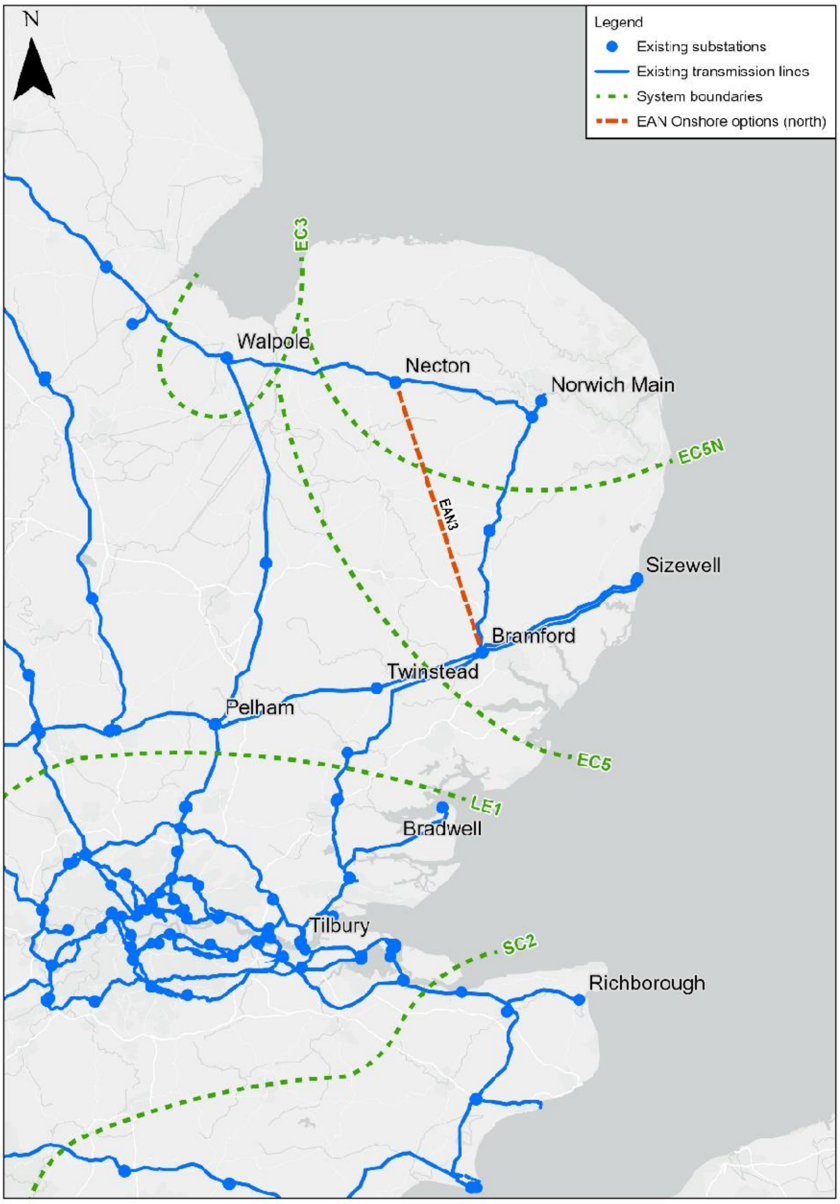
9. EAN3 – Necton to Bramford

9.1 Introduction

9.1.1 Strategic option (SO) EAN 3 involves a new 400kV transmission connection between existing Necton substation and the existing Bramford substation, a distance of approximately 85 km. shown in Figure 9.1. The existing Bramford substation would require modification to accommodate additional circuits, which would be subject to further design and resilience considerations.

9.1.2 With the majority of proposed generation connections to be made between Norwich Main and Necton, this connection not only provides capacity for contracted connections but would accommodate future connections by having additional capacity available.

Figure 9.1 – Option EAN 3 Necton to Bramford



9.2 Environmental appraisal

Landscape and visual

9.2.1 Much of the study area comprises relatively limited constraints to AC OHL which can be addressed by conventional approaches. The eastern central part of the study area around Thetford has a cluster of sensitive receptors which could be avoided if routeing west.

9.2.2 Whilst it should be possible with this option to avoid a good proportion of potential other adverse effects on the landscape and visual amenity, some significant residual effects are possible for residents along affected settlement edges and scattered properties through the introduction of a new AC OHL.

9.2.3 This option is moderately constrained, with a number of opportunities to avoid constraints and for mitigation through more detailed assessment, siting and installation which would reduce potential for significant landscape and visual effects, but a number of adverse effects may remain.

9.2.4 There may be opportunity for paralleling existing OHLs to reduce the spread of infrastructure in the south of the study area.

Historic environment

9.2.5 The scheduled monuments are distributed throughout the study area and include sites dating from the prehistoric period onwards. While examples of scheduled monuments have been recorded throughout the study area, there are several areas where large concentrations of sites have been recorded. These include a number of medieval sites near Castle Acre at the northwest limits of the study area, Roman and medieval sites to the north of Watton, and a number of sites between Thetford and Attleborough including two linear earthworks. Larger scheduled monuments in the southern half of the study area include Baylham Roman Site near Needham Market, although smaller assets are located throughout the southern half of the study area including a number of moated sites.

9.2.6 Listed buildings have been recorded throughout the study area, with the vast majority being Grade II listed. Although a relatively large number of Grade I and II* buildings have been recorded the main focus of these are the settlements scattered throughout the study area, although Grade II listed buildings have also been recorded throughout the landscape.

9.2.7 A number of RPGs have also been recorded throughout the study area. These include Grade I, II*, and II designations and are again distributed throughout the study area, although significant concentrations include the western side of the study area between Castle Acre and Thetford. Two Grade I listed parks and gardens also fall within the southeast corner of the study area near Needham Market.

9.2.8 Although a review of non-designated assets was not undertaken as part of this options appraisal, the Defence of Britain data set was examined and a large number of assets were recorded in the study area. These include a large concentration of defensive structures following the A1088 between Thetford and Elmswell, and this grouping formed part of a ‘Stop Line’ constructed during the Second World War.

9.2.9 It is likely that designated assets, such as scheduled monuments and listed buildings would be avoidable. 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.

9.2.10 There is the potential for significant impacts on the setting, of high value designated assets identified throughout the corridor. This includes the parks and gardens in the northwestern section of the study area, the two parks and gardens near Needham Market, as well as the scheduled monuments and listed buildings throughout the study area.

9.2.11 Mitigation would 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.

Ecology

9.2.12 Statutory designated sites for nature conservation are likely to be avoidable within this study area.

9.2.13 A principal consideration is the Breckland SPA/SAC/SSSI complex which is located within the northwest of the study area. Whilst this site is avoidable there is the potential for impacts on the interest features associated with both habitats and species for which the sites are designated both during construction and operation. Routeing would therefore need to consider bird flight paths. There is the potential that a new AC OHL could introduce a collision risk, avoidance, and disruption of flight paths, and/or mortality sources of impact for a number of bird species. Recommended measures for mitigating for bird collision and mortality from AC OHL prioritise eliminating exposure by undergrounding sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g., insulated components, greater air space between lines).

9.2.14 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitats and Species Regulations 2017.

Physical environment

9.2.15 Any AC OAC route between Necton and Bramford substations would have to cross over several unavoidable watercourses and associated flood zones. Given the extent of Flood Zones 2 & 3, across the entire study area, it is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

9.2.16 Crossings of main rivers, Flood Zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable.

9.2.17 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

9.3 Socio-economic appraisal

Settlements and populations

9.3.1 There are five main settlements within this study area and smaller settlements scattered throughout. Population density increases towards the south.

9.3.2 The south of the study area is more densely populated with multiple settlements which could impact on the ability to route an AC OHL in this area without multiple angles.

9.3.3 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 adverse visual effects which are set out in the landscape and visual appraisal.

9.3.4 Standard best practice guidelines should be followed to reduce potential noise and air quality effects during construction. Control measures should be put in place to potential impacts associated with construction traffic.

Tourism and recreation

9.3.5 There are a number of NCN routes and unnamed routes running through the study area. A national trail runs north to south in the northern half of the study area. There are two Country Parks within the study area. Knettishall Heath near Thetford and Orwell within Ipswich.

9.3.6 There is the potential for temporary adverse effects associated with severance should cycle routes or national trails need to be temporarily closed during construction, however this is likely to be the case with any option, and effects would be temporary. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN and national trail and these effects would be permanent.

9.3.7 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route and national trails should part of a cycle route or national trail be closed during construction.

Land use

9.3.8 Known BMV land (Grade 1 and 2) is present in the study area with the majority being Grade 3 BMV land. A small area of Grade 1 BMV land is located near the southern boundary, this is considered avoidable. Grade 2 is scattered throughout this study area and is considered unavoidable. Loss of BMV likely to be limited for the AC OHL route.

9.3.9 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints but this is unlikely to be significant. Other land uses are likely to be avoidable.

9.3.10 Standard best practice guidelines should be followed to reinstate agricultural land following construction.

9.3.11 Golf courses, Countryside Rights of Way Access Land Parcels and Forest and Country Parks should be avoided by routeing where possible.

Infrastructure

9.3.12 There are four trunk roads within this study area, including the A14, A12, A11 and A47. The A47 is located north of Necton Substation, A12 is located south of Bramford Substation. The A47 and A12 would not be affected. The A11 and A14 are unavoidable.

9.3.13 There are railway lines running through the study area. At least two railway lines would be unavoidable within this option.

9.3.14 Ipswich Wet Dock and Cliff Quay Port are located at Ipswich. There are nine airports including Honnignton Airfield, Crowfield Airfield, Wattisham Airfield, Elmsett Airfield and five unnamed airports. It is considered the airports and ports are avoidable.

9.3.15 Where crossings of other infrastructure is required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

9.3.16 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.

9.3.17 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

9.3.18 Routeing of a new AC OHL would have to take account of the nine 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.

9.4 Technical scope and costs

9.4.1 Technical analysis of option EAN 3 is as follows:

- This option to connect a 85km circuit between Necton and Bramford, takes energy South to the existing Bramford substation.
- The existing Bramford substation would require modification to accommodate additional circuits, which will be subject to further design and resilience considerations.

9.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

9.4.3 Option EAN 3 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;

- HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, six overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
- The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, four overall, this cost is included in brackets () in the table.

- **Substation works**
  - Extension to Necton 400kV Substation by 2 bays to accommodate new circuits.
  - Extension to Bramford substation by 2 bays to accommodate new circuits.

Table 9.1 – below sets out the capital costs for option EAN 3 considering substation works and each technology option.

Item	Need	EAN 3 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£36.8m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 85 km	New Circuit across EC5 North	£338.3m	£3,638.2m	£3,677.1m	£2,391.1m (£1,594.1m)
Total Capital Cost		**£375.1**	**£3,675.0m**	**£3,713.9m**	**£2,427.9m (£1,630.9m)**

9.4.4 Table 9.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 – EAN 3 Circuit Lifetime Cost Summary

Land Based option	EAN 3 AC OHL	EAN 3 AC Cable	EAN 3 AC GIL	EAN 3 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£338.3m	£3,638.2m	£3,677.1m	£2,391.1m (£1,594.1m)
NPV of cost of losses over 40 years	£238.4m	£174.9m	£110.7m	£471.2m (£314.1m)
NPV of operation & maintenance costs over 40 years	£5.0m	£16.4m	£5.0m	£172.1m (£114.7m)
Circuit Lifetime Cost of new circuits	**£582m**	**£3,829m**	**£3,793m**	**£3,034m (£2,023m)**

9.4.5 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAN 3, 85 km connection between a Necton and Bramford 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

10. EAN4 – Norwich Main to Bramford

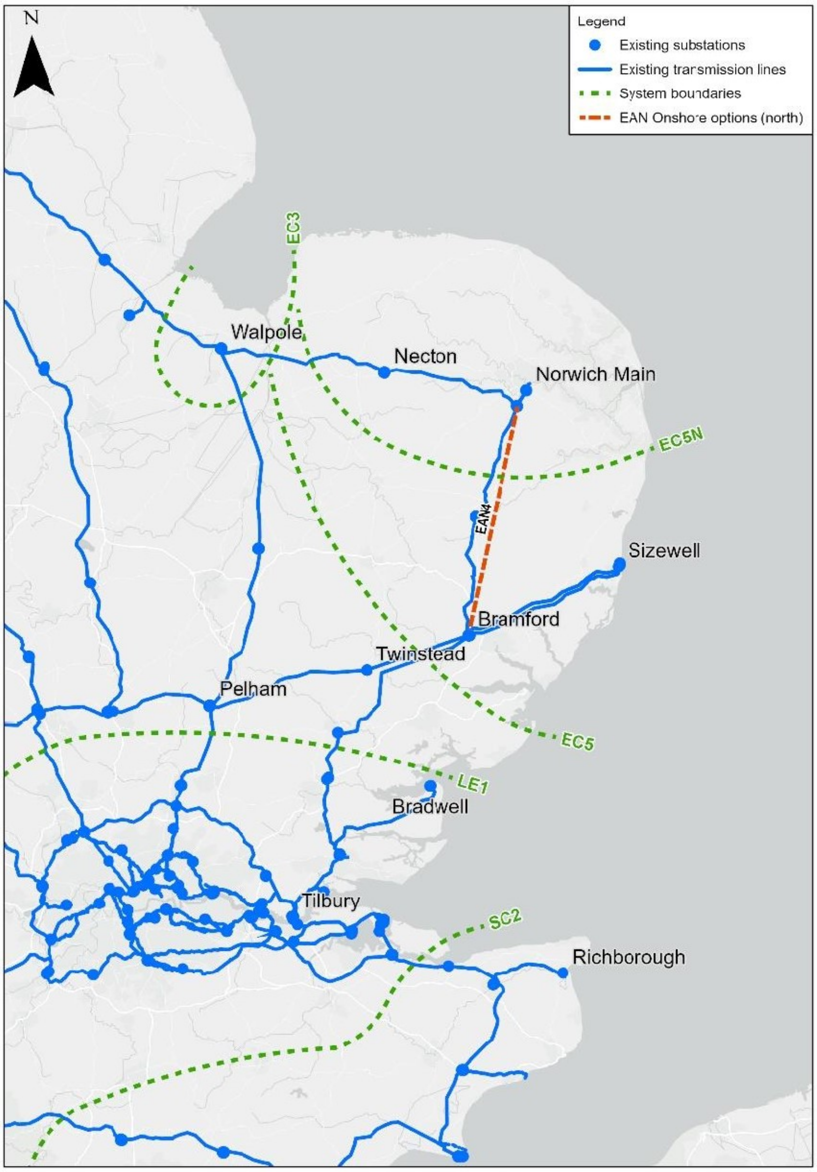
10.1 Introduction

10.1.1 Strategic option (SO) EAN 4 involves a new 400kV transmission connection between the existing Norwich Main substation and the existing Bramford substation, a distance of approximately 80 km. This is shown in Figure 10.1 below.

10.1.2 The existing Bramford substation would require modification to accommodate additional circuits, which would be subject to further design and resilience considerations.

10.1.3 With the majority of proposed generation connections to be made between Norwich and Necton, this connection not only provides capacity for contracted connections but would accommodate future connections by having additional capacity available.

Figure 10.1 – Option EAN 4 Norwich Main to Bramford



10.2 Environmental appraisal

Landscape and visual

10.2.1 Much of the study area comprises relatively limited constraints to an AC OHL which can be addressed by conventional approaches e.g., routeing. Whilst it should be possible with this option to avoid a good proportion of potential adverse effects on the landscape and visual amenity; some significant residual effects are possible for residents along affected settlement edges and scattered properties, particularly if there are islanding of properties between the two OHLs; existing and proposed.

10.2.2 This option has few constraints. Some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction which would reduce the potential for some visual effects. Some limited significant residual visual effects are possible.

10.2.3 There may be opportunity for paralleling the existing OHL throughout this study area to reduce the spread of infrastructure. In some locations it may be challenging to identify a parallel alignment due to settlement and other land uses.

Historic environment

10.2.4 Designated sites are distributed throughout the study area, although a number are located at the southern end of the option near Needham Market, including Shrubland Hall Grade I Registered Park and Garden, and Baylham Roman site which is a scheduled monument and lies adjacent to the Shrubland. Other scheduled monuments have also been recorded throughout the study area, although concentrations have been recorded within central sections of the study area. A large scheduled area also exists to the south of Norwich, at the northern end of the study area. The latter site includes a large multi-period site located less than 800m northeast of Norwich substation, and the existing OHL running north from the substation passes this scheduled monument.

10.2.5 The majority of listed buildings are focused on settlements, with concentrations in towns and villages such as Diss, Stowmarket, and Needham Market, as well as Ipswich.

10.2.6 Only a limited number of military remains have been recorded through the option, and most of these are near the settlements of Diss and Ipswich. Other non-designated assets have not been considered as part of the current assessment.

10.2.7 It is likely that designated assets, such as scheduled monuments and listed buildings would 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.

10.2.8 There is the potential for significant impacts on the setting, with many high value designated assets identified throughout the corridor. It must also be considered that further above ground infrastructure on the south side of Norwich, where a number of scheduled monuments are recorded, could result in a cumulative impact on these receptors.

10.2.9 Mitigation would 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.

Ecology

10.2.10 There is one site subject to a European designation within the study area (Norfolk Valley Fens SAC), this is located in the far north of the study area to the northwest of Norwich and is unlikely to be affected.

Physical environment

10.2.11 Any AC OAC route between Norwich Main and Bramford substations would have to cross over several unavoidable watercourses and associated flood zones. Given the extent of Flood Zones 2 & 3, across the entire study area, it is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

10.2.12 Crossings of main rivers, Flood Zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable.

10.2.13 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

10.3 Socio-economic appraisal

Settlements and populations

10.3.1 There are three main settlements boundaries including Ipswich, Stowmarket and Wymondham within this study area. Population density is greater in the south.

10.3.2 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 adverse visual effects which are set out in the landscape and visual appraisal.

Tourism and recreation

10.3.3 There are a number of unnamed NCN routes that run through the study area. NCNs extend across the middle of the study area and are prominent in the south, particularly at Ipswich.

10.3.4 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN.

10.3.5 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route should part of a cycle route be closed during construction.

Land use

10.3.6 There are no areas of Grade 1 BMV land. Grade 2 BMV land occurs in fragmented areas throughout, however, is more prominent in south. Grade 3 BMV agricultural land is the most prominent land type classification. Loss of BMV likely to be limited for the AC OHL route.

10.3.7 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints but this is unlikely to be significant. Other land uses are likely to be avoidable.

10.3.8 Standard best practice guidelines should be followed to reinstate agricultural land following construction.

10.3.9 Golf courses and other land uses should be avoided by routeing where possible.

Infrastructure

10.3.10 There are no motorways within this study area. The A47 and A11 are located in the northwest corner of the study area and are avoidable. The A14 is located across the southwest corner of the study area and is unavoidable.

10.3.11 There are a number of railway lines that run through the study area. There are five railway lines within this study area. One railway line extends across the northwest corner of the study area. A railway line extends from Norwich through the middle of the study area to Ipswich via Haughley (located near the western border in the south). Three further railway lines are located in Ipswich. It is considered at least one railway line is unavoidable.

10.3.12 Ipswich Wet Dock is located in Ipswich. Three aerodromes are located in the south of this study area including Crowfield Airfield, Elmsett Aerodrome and Wattisham Airfield is considered the airports and ports are avoidable.

10.3.13 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

10.3.14 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 temporarily closed during construction.

10.3.15 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

10.3.16 Routeing of a new AC OHL would have to take account of the three 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 EAN 4 is as follows:

- This option to connect a 80km circuit between Norwich and Bramford, takes energy South to the existing Bramford substation.
- The existing Bramford substation would require modification to accommodate additional circuits, which will be subject to further design and resilience considerations.

10.4.2 With the majority of proposed generation connections to be made between Norwich and Necton, this connection not only provides capacity for contracted connections but will accommodate future connections by having additional capacity available.

10.4.3 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

10.4.4 Option EAN 4 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, six overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
  - The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, four overall, this cost is included in brackets () in the table.
- **Substation works**
  - Extension to Norwich 400kV Substation by 2 bays to accommodate new circuits.
  - Extension to Bramford substation by 2 bays to accommodate new circuits.

Table 10.1 – below sets out the capital costs for option EAN 4 considering substation works and each technology option.

Item	Need	EAN 4 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£36.8m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 80 km	New Circuit across EC5 North	£318.4m	£3,421.3m	£3,460.8m	£2,344.7m (£1,594.1m)

Item	Need	EAN 4 Capital Cost			
Total Capital Cost		**£355.2m**	**£3,458.1m**	**£3,497.6m**	**£2,381.5m (£1,630.9m)**

10.4.5 Table 10.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 – EAN 4 Circuit Lifetime Cost Summary

Land Based option	EAN 4 AC OHL	EAN 4 AC Cable	EAN 4 AC GIL	EAN 4 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£318.4m	£3,421.3m	£3,460.8m	£2,344.7m (£1,563.2m)
NPV of cost of losses over 40 years	£224.4m	£161.3m	£104.2m	£471.2m (£314.1m)
NPV of operation & maintenance costs over 40 years	£4.7m	£15.5m	£4.7m	£172.1m (£114.7m)
Circuit Lifetime Cost of new circuits	**£548m**	**£3,598m**	**£3,570m**	**£2,988m (£1,992m)**

10.4.6 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAN 4, 80 km connection between a Norwich and Bramford 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

11. EAS1 – Twinstead to Tilbury

11.1 Introduction

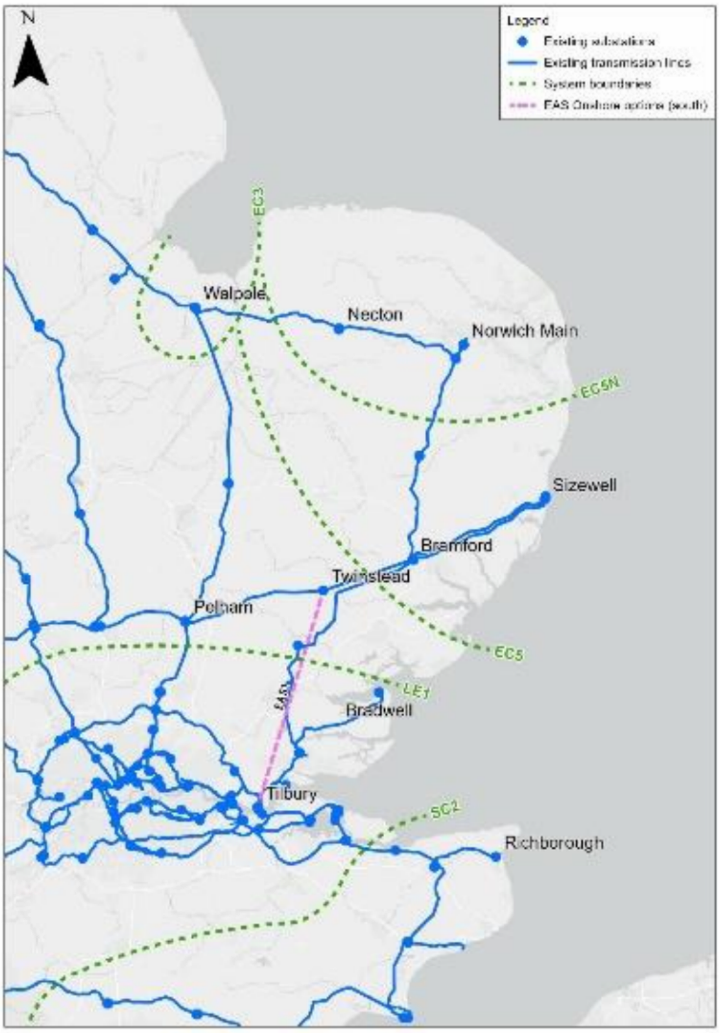
11.1.1 Strategic option (SO) EAS 1 involves a new 400kV transmission connection between the new substation at Twinstead and the existing Tilbury substation, a distance of approximately 80 km. shown in Figure 11.1. Twinstead substation would require a complete redesign from current proposals as described below.

11.1.2 Currently the proposed Twinstead substation is a small connection of demand connection to the local Distribution Network Operator. This site is not sufficient for the connection of new circuits, so a new larger site would need to be established to facilitate the connection of multiple circuits.

11.1.3 If this option were to be selected in combination with northern options connecting to Pelham (EAN1) or Bramford (EAN3 and EAN4), all 4 circuits travelling east from Bramford would need to be turned into the new Twinstead substation.

11.1.4 This option would facilitate the connection of the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation, if connection were made at the new Twinstead substation.

Figure 11.1 – Option EAS 1 Twinstead to Tilbury



11.2 Environmental appraisal

Landscape and visual

11.2.1 One nationally designated landscape, the Dedham Vale AONB, is present in the study area. However, due the location of the AONB in the northeastern corner of the study area, it is assumed that it would be avoided and therefore is not considered a particular constraint to the option.

11.2.2 Paralleling the exiting line from Twinstead would be challenging due to its alignment and the potential to island properties between the existing and proposed OHL.

11.2.3 This option is moderately to heavily constrained due to areas of denser settlement to the south. Some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction which would reduce the potential for some visual effects, including consideration of the relationship between the option and the existing 400kV OHL. Some significant residual visual effects are possible.

Historic environment

11.2.4 Scheduled monuments are located throughout the study area, although concentrations have been recorded in the southern section towards Canvey Island and Tilbury, as well as in the central area.

11.2.5 Parks and Gardens in the study area are focused on the central and northern sections of the study area, with some of the largest examples flanking the A12 as it passes through the study area, and in the northeast corner near Halstead, although the extensive Thorndon Hall, with its grounds designed by Capability Brown, near the southwest also represents a key designed landscape.

11.2.6 The site of the Battle of Maldon represents the only battlefield in the study area and is located on the eastern limit of the study area near Maldon and the River Blackwater.

11.2.7 Military defences have also been identified throughout the option, with a significant cluster in the northeast corner where the main railway line passes through the option, and in the central area where they flank the A130. This latter cluster forms part of a Second World War ‘stop line’. Other non-designated assets have not been considered as part of the assessment.

Ecology

11.2.8 European and national designated sites are likely to be avoidable.

11.2.9 Whilst sites are avoidable there are number of SPAs on the eastern edge of the study area and Hanningfield Reservoir which are designated for bird populations. Routeing would therefore need to consider bird flight paths. Opportunities may exist to parallel the existing 4VB overhead line, which may reduce potential for collision risk due to bird species being habituated in this area. Although should a new AC OHL parallel the existing OHL within this study area this would require the AC OHL to cross an RSPB reserve to the northeast of Tilbury.

11.2.10 Recognised mitigation measures for AC OHL impacts to bird assemblages would need to be used wherever appropriate. Mitigation for impacts of AC OHL connections on bird populations are available, such as bird diverters, 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 sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g. insulated components, greater air space between lines).

11.2.11 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitats and Species Regulations 2017.

Physical environment

11.2.12 It is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

11.2.13 Crossings of main rivers, Flood Zones 2 or 3 are unlikely to be avoidable.

11.2.14 Significant operational effects from the AC OHL are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

11.2.15 Any extension to Tilbury substation would be within Flood Zone 3 therefore additional mitigation measures may be required.

11.3 Socio-economic appraisal

Settlements and populations

11.3.1 There are fifteen main settlements which extend into this study area. Population density is greater in the south. Due to the density of the settlement pattern particularly in the south it is likely that an AC OHL would need to be routed near some settlements.

11.3.2 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 adverse visual effects which are set out in the landscape and visual appraisal.

Tourism and recreation

11.3.3 There are a number of NCNs routes and unnamed routes that run through the study area. Known NCNs within this study area include Flitch Way, Mardyke Valley Route and the Heron Trail. NCN's are more prominent in the north of this study area. It is considered at least three NCN's are unavoidable.

11.3.4 There are 15 country parks within the study area located predominantly to the south between Chelmsford and Basildon.

11.3.5 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction however, this is likely to be the case with any option, and effects would be temporary. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN and these effects would be permanent.

11.3.6 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route should part of a cycle route be closed during construction.

Land use

11.3.7 Grade 1 BMV land is located in the southeast and southwest corner of the study area. Grade 2 BMV land is located in fragmented sections throughout the study area, however, is more prominent along the southern border and in the northwest. Grade 3 BMV agricultural land is the most prominent land type classification in the study area. Loss of BMV is likely to be limited for the AC OHL route.

11.3.8 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints, but this is unlikely to be significant.

11.3.9 Standard best practice guidelines should be followed to reinstate agricultural land following construction.

11.3.10 There is the potential to oversail a golf course due to the density of the settlement pattern coupled with other constraints. Other land uses should be avoided by routeing where possible.

Infrastructure

11.3.11 The M25 motorway, A13 and A282 is located in the southwest corner of this study area. The A12 extends diagonally across the study area from Ingatestone at the western border in the south to Colchester at the eastern border in the north. The A120 extends across the study area in the north from Rayne in the west to Colchester in the east. It is considered the A120 and A12 are unavoidable.

11.3.12 There are a number of railway lines within this study area. Railway lines connect the urban settlements described above. A number of railway lines extend across the entire reach of the study area and which are therefore unavoidable. This includes a railway line extending diagonally across the study area between Brentwood and Colchester. A railway line extends from Brentwood to Wickford, here two railway lines diverge from Wickford to Hockley and South Woodham Ferrers. A railway line extends between Benfleet in the east to West Horndon in the west. It is considered the AC OHL would need to cross at least three railway lines and possibly more.

11.3.13 Four aerodromes are located within this study area including Essex Air Ambulance Airbase/Earls Colne Airfield, Napps Field, Stow Maries Aerodrome and an unnamed airfield at Great Maplestead in the north. There are four ports and harbours located in the south of this study area including London Cruise Terminal, London Gateway Port, Tilbury Docks and the Town Pier in Tilbury. The locations of airfields and ports/harbours are easily avoidable.

11.3.14 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

11.3.15 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.

11.3.16 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

11.3.17 Routeing of a new AC OHL would have to take account of the four 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.

11.4 Technical scope and costs

11.4.1 Technical analysis of option EAS 1 is as follows:

- This option to connect a 80km circuit between New Twinstead and Tilbury, takes energy south to the existing substation at Tilbury.
- Currently the proposed Twinstead Substation is a small connection of demand connection to the local Distribution Network Operator. This site is not sufficient for the connection of new circuits, so a new larger site would need to be established to facilitate the connection of multiple circuits, generation and interconnectors.
- If this option is selected in combination with EAN option connecting to Bramford and Pelham, then all 4 circuits travelling east from Bramford need to be turned into the new Twinstead substation.
- Additional costs would be incurred to allow this option to facilitate the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation. These would be for a connection at a new Twinstead substation and incremental costs for the generators and interconnector to reach the connection point. This would also increase the cost for any future offshore generation, required to meet the national net zero by 2050 targets, having to connect to the same location.

11.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

11.4.3 Option EAS 1 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;

- HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, six overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
- The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, four overall, this cost is included in brackets () in the table.

- **Substation works**
  - New Twinstead 400kV substation able to accommodate 14 bays (22 bays if option chosen in combination with non Twinstead EAS option)
  - Extension to Tilbury 400kV Substation by 2 bays to accommodate new circuits.

Table 11.1 – EAS 1 Capital Cost Summary.

Item	Need	EAS 1 Capital Cost			
Substation Works	Facilitate generation and connect new circuits	£136.0m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 80 km	New Circuit across EC5 and LE1	£318.4m	£3,421.3m	£3,460.8m	£2,344.7m (£1,563.2m)
Total Capital Cost		**£454.4m**	**£3,557.3m**	**£3,596.8m**	**£2,480.7m (£1,699.2m)**

11.4.4 Table 11.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 11.2 – EAS 1 Circuit Lifetime Cost Summary

Land Based option	**EAS 1 AC OHL**	**EAS 1 AC Cable**	**EAS 1 AC GIL**	**EAS 1 HVDC (Min 4000 MW rating)**
Capital Cost of New Circuits	£318.4m	£3,421.3m	£3,460.8m	£2,344.7m (£1,563.2m)
NPV of cost of losses over 40 years	£224.4m	£161.3m	£104.2m	£471.2m (£314.1m)
NPV of operation & maintenance costs over 40 years	£4.7m	£15.5m	£4.7m	£172.1m (£114.7m)
Circuit Lifetime Cost of new circuits	**£548m**	**£3,598m**	**£3,570m**	**£2,988m (£1,992m)**

11.4.5 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAS 1, 80 km connection between a New Twinstead and Tilbury 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

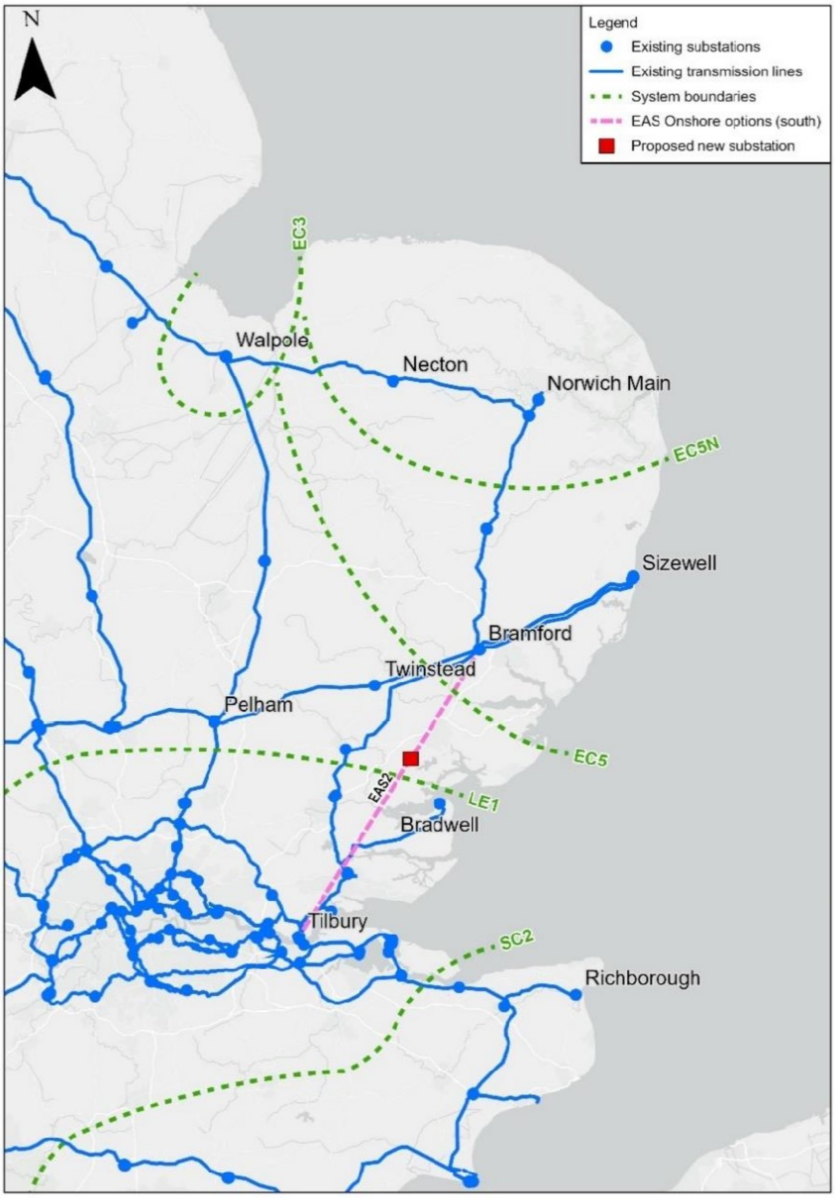
12. EAS2 – Bramford via new substation to Tilbury

12.1 Introduction

12.1.1 Strategic option (SO) EAS 2 involves a new 400kV transmission connection between the existing substation at Bramford via a new substation enroute and the existing Tilbury substation, a distance of approximately 100 km. shown in Figure 12.1.

12.1.2 This option facilitates the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at their existing contracted point of connection.

Figure 12.1 – Option EAS 2 Bramford via New Substation to Tilbury



12.2 Environmental appraisal

Landscape and visual

12.2.1 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 Dedham Vale AONB and South Suffolk and North Essex Claylands NCA, 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 would be adverse visual effects to residents along affected settlement edges, scattered properties, and visitors to RPGs and Country Parks through increased ‘wirescape’.

12.2.2 The Dedham Vale AONB is avoidable within this study area, although to route from Bramford to a new substation on the Tendring Peninsular would require a significantly longer AC OHL route.

12.2.3 A route through the AONB would require at least 5km of undergrounding. Careful route alignment/siting is important to minimise long term effects on characteristic and highly sensitive landcover, such as Ancient Woodland (considered irreplaceable) as a result of installing an underground connection. Trenchless installation techniques or other technology might be required to avoid effects on Ancient Woodland cover.

12.2.4 This option is significantly constrained, however, some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction or installation which would reduce the potential for some significant landscape and visual effects, however there is the potential for residual significant effects.

Historic environment

12.2.5 Parks and Gardens and scheduled monuments are distributed throughout the corridor, although there is a large concentration of scheduled monuments to the south of Colchester, and two scheduled monuments flank the existing Tilbury power station. Two extensive Parks and Gardens (Weald Park and Thorndon Hall) also occupy a large area of land near Brentwood.

12.2.6 Military defences exist throughout the study area, however there are relatively few significant clusters. Small clusters have been recorded along the A20, where the remains of a Second World War ‘stop line’ can be traced. Other non-designated assets have not been considered as part of the assessment.

12.2.7 It is likely that designated assets, such as scheduled monuments and listed buildings would be avoidable. 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.

12.2.8 There is the potential for significant impacts on the setting 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.

12.2.9 Mitigation would be required and could include a phased programme of works including geophysical survey, archaeological evaluation trenching, and full archaeological excavation to mitigate physical impacts.

12.2.10 The design of any above ground infrastructure required, as well as screening/planting, could potentially mitigate impacts on the setting of designated assets.

Ecology

12.2.11 Whilst European and national designated sites are likely to be avoidable to route from a new substation on the Tendring Peninsular to Tilbury would require the AC OAC to be routed around Colne and Blackwater Estuary which would increase the length of the AC OHL unless a trenchless solution was used to cross this feature and associated designated sites.

12.2.12 Whilst sites are avoidable a large proportion of the study area is designated as SPAs on the eastern edge. Routeing would therefore need to consider bird flight paths. Opportunities may exist to parallel the existing 4VB overhead line, this may reduce potential for collision risk due to bird species being habituated in this area. Should a parallel solution be achievable to minimise potential impacts on species of bird this would require the AC OHL to cross an RSPB reserve to the northeast of Tilbury.

12.2.13 Recognised mitigation measures for AC OHL impacts to bird assemblages would need to be used wherever appropriate. Mitigation for impacts of AC OHL prioritise eliminating exposure by undergrounding sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g., insulated components, greater air space between lines).

12.2.14 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitat and species Regulations 2017.

Physical environment

12.2.15 It is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

12.2.16 Crossings of main rivers, flood zones 2 or 3 are likely to be unavoidable.

12.2.17 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

12.2.18 The location of the new sub is not yet known but avoidance of Flood Zones 1 and 3 should be achievable on the Tendring Peninsular.

12.2.19 Any extension to Tilbury substation would be within Flood Zone 3 therefore additional mitigation measures may be required.

12.3 Socio-economic appraisal

Settlements and populations

12.3.1 There are 22 main settlements within this study area and population density increases towards the south. Whilst settlements are potentially avoidable, due to the density of the study area in the south it is likely that a new AC OHL would need to be routed near to settlements.

12.3.2 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 adverse visual effects which are set out in the landscape and visual appraisal.

Tourism and recreation

12.3.3 There are a number of NCNs routes within this study area. It is considered multiple cycle routes would be unavoidable within this option. There are also 27 Country Parks. These are found slightly more to the southern half of the study area with a cluster between Brentwood and Basildon.

12.3.4 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction, however this is likely to be the case with any option and effects would be temporary. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN and these effects would be permanent.

12.3.5 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route should part of a cycle route be closed during construction.

Land use

12.3.6 Grade 1 BMV land is located in the east of the study area. Grade 2 BMV land is fragmented throughout this study area. Grade 3 BMV agricultural land is prominent land type classification in the study area. Bramford Substation is located on Grade 2 BMV land. Loss of BMV likely to be limited for the AC OHL route but could be more significant where there are new substations.

12.3.7 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints but this is unlikely to be significant. Loss of BMV due to the substation should be avoidable. Other land uses are likely to be avoidable.

12.3.8 There is the potential to oversail a golf course due to the location of golf courses in relation to other constraints. Other land uses should be avoided by routeing where possible.

Infrastructure

12.3.9 The M25 motorway, A13 A1089, and A282 are located in the southwest corner of this study area. The A12 extends diagonally across the study area between Ipswich and Brentwood. The A120 extends across the study area in the north between Braintree and Harwich. The A14 extends around the urban settlement of Ipswich. It is considered that the A120 and A12 are unavoidable.

12.3.10 There are railway lines within this study area. Railway lines connect the urban settlements described above. It is considered at least three railway lines, and possibly more would need to be crossed within this option.

12.3.11 Ten aerodromes are located within this study area, including Damyns Hall Aerodrome, Elsett, Essex Air Ambulance Airbase/Earls Colne Airfield, Great Oakley Airfield, London Southend Airfield, Napps Field, Stoke Golding Airfield, Stow Maries Aerodrome, Wattisham Airfield and an unnamed airfield located at Great Wakering. Ten ports and harbours area located within this study area including Chatham Docks, Cliff Quay, Harwich International Port, Ipswich Wet Dock, London Cruise Terminal, London Gateway Port, London Thamesport, Port of Felixstowe/Freightliner Terminal, Tilbury Docks, Town Pier. The locations of airfields and ports/harbours are considered avoidable.

12.3.12 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

12.3.13 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.

12.3.14 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

12.3.15 Routeing of a new AC OHL would have to take account of the ten 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.

12.4 Technical scope and costs

12.4.1 Technical analysis of option EAS 2 is as follows:

- This option to connect a 100km circuit between Bramford via New Connection Substation and Tilbury, takes energy south via a New Connection Substation to the existing substation at Tilbury.
- This option facilitates the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at their existing contracted point of connection.

12.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

12.4.3 Option EAS 2 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, nine overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.

- The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, six overall, this cost is included in brackets () within the table.
- Both HVDC options for this connection will be Three ended circuits with number HVDC convertor stations indicated above required at all three ends.

- **Substation works**
  - Extension to Bramford substation by 2 bays to accommodate new circuits.
  - New Connection Substation able to accommodate 12 bays.
  - Extension to Tilbury 400kV Substation by 2 bays to accommodate new circuits.

Table 12.1 – below sets out the capital costs for option EAS 2 considering substation works and each technology option.

Item	**Need**	**EAS 2 Capital Cost**			
Substation Works	Facilitate generation and connect new circuits	£141.3m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 100 km	New Circuit across EC5 and LE1	£398.0m	£4,290.0m	£4,326.0m	£3,331.7m (£2,221.1.m)
Total Capital Cost		**£539.3**	**£4,431.3m**	**£4,467.3m**	**£3,473.0m (£2,362.4)**

12.4.4 Table 12.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 12.2 – EAS 2 Circuit Lifetime Cost Summary

Land Based option	EAS 2 AC OHL	EAS 2 AC Cable	EAS 2 AC GIL	EAS 2 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£398.0m	£4,290.0m	£4,326.0m	£3,331.7 (£2,221.1m)
NPV of cost of losses over 40 years	£280.0m	£206.3m	£130.2m	£706.9m (£471.2m)
NPV of operation & maintenance costs over 40 years	£5.8m	£19.7m	£5.9m	£257.9m (£114.7m)
Circuit Lifetime Cost of new circuits	**£684m**	**£4,516m**	**£4,462m**	**£4,297m (£2,807m)**

12.4.5 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAS 2, 100 km connection between Bramford via New Connection Substation and Tilbury 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

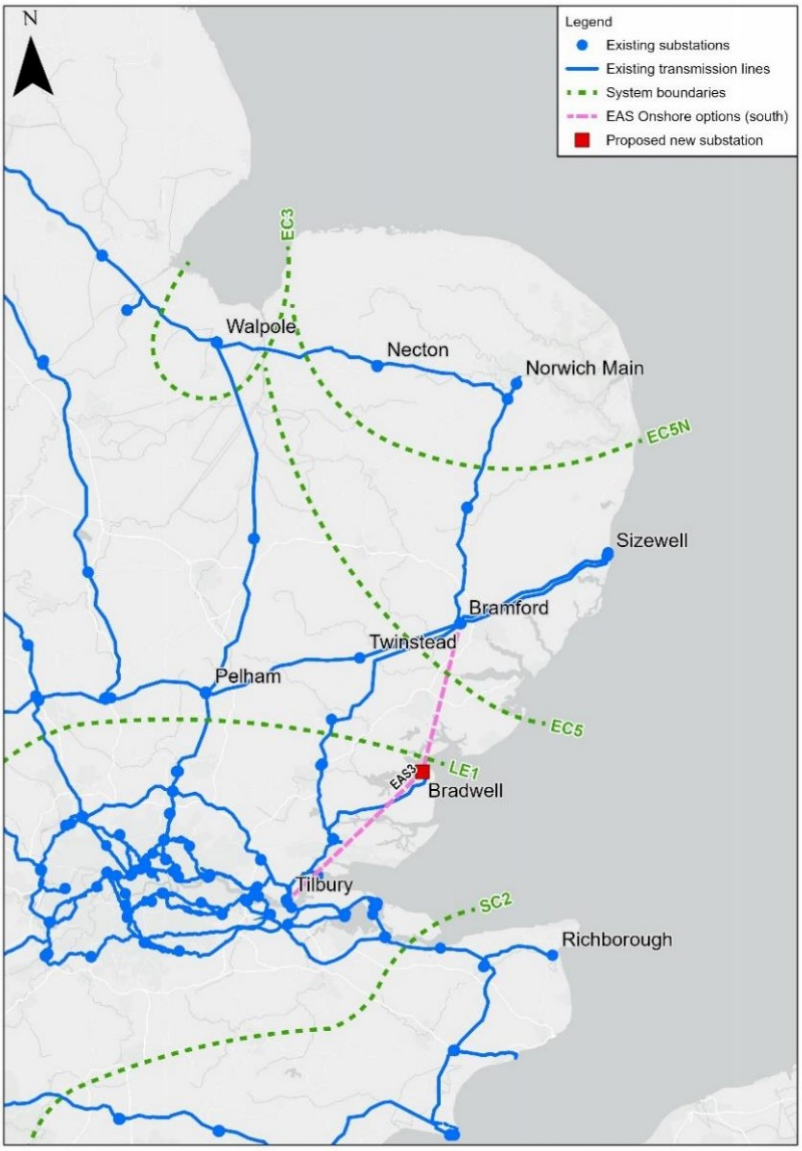
13. EAS3 – Bramford via new substation at Bradwell to Tilbury

13.1 Introduction

13.1.1 Strategic option (SO) EAS 2 involves a new 400kV transmission connection between the existing substation at Bramford via a new substation at Bradwell enroute and the existing Tilbury substation, a distance of approximately 130 km. shown in Figure 13.1.

13.1.2 This option facilitates the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at a new Bradwell substation point of connection. The location of a new substation at Bradwell would be in the vicinity of the decommissioned Bradwell nuclear power station and existing lower voltage substation.

Figure 13.1 – Option EAS 2 Bramford via New Substation to Tilbury



13.2 Environmental appraisal

Landscape and visual

13.2.1 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 Dedham Vale AONB and South Suffolk and North Essex Claylands NCA, 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 would be adverse visual effects to residents along affected settlement edges, scattered properties, and visitors to RPGs and Country Parks through increased ‘wirescape’.

13.2.2 The Dedham Vale AONB is avoidable within this study area, although to route from Bramford to a new substation at Bradwell would require a significantly longer AC OHL route.

13.2.3 A route through the AONB would require at least 5km of undergrounding. Careful route alignment/ siting is important to minimise long term effects on characteristic and highly sensitive landcover, such as Ancient Woodland (considered irreplaceable) as a result of installing an underground connection. Trenchless installation or other technology might be required to avoid effects on Ancient Woodland cover.

13.2.4 Careful siting and design of the new substation Bradwell would likely have some adverse landscape and visual impacts due to its location on the coastline at the mouth of the estuary of the Rivers Colne and Blackwater; albeit there is exiting large infrastructure already present locally.

13.2.5 This option is significantly constrained, however, some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction or installation which would reduce the potential for some significant landscape and visual effects.

Historic environment

13.2.6 Parks and Gardens and scheduled monuments are distributed throughout the corridor, although there is a large concentration of scheduled monuments to the south of Colchester, and two scheduled monuments flank the existing Tilbury power station. Two extensive Parks and Gardens (Weald Park and Thorndon Hall) also occupy a large area of land near Brentwood.

13.2.7 Military defences exist throughout the area, however there are relatively few significant clusters. Small clusters have been recorded along the A20, where the remains of a Second World War ‘stop line’ can be traced. Other non-designated assets have not been considered as part of the assessment.

13.2.8 It is likely that designated assets, such as scheduled monuments and listed buildings would be avoidable. 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.

13.2.9 There is the potential for significant impacts on the setting 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.

13.2.10 Mitigation would be required, and could include a phased programme of works including geophysical survey, archaeological evaluation trenching, and full archaeological excavation to mitigate physical impacts.

Ecology

13.2.11 Whilst European and national designated sites are likely to be avoidable to route to and from a new substation at Bradwell would require the AC OAC to be routed around Colne and Blackwater Estuary and then back again from Bradwell which would increase the length of the AC OHL unless an underground solution was used to cross this feature and associated designated sites.

13.2.12 Whilst sites are avoidable large proportion of the eastern side of the study area is designated as SPAs on the eastern edge of the study area. Routeing would therefore need to consider bird flight paths. Opportunities may exist to parallel the existing 4VB overhead line, this may reduce potential for collision risk due to bird species being habituated in this area. Should a parallel solution be achievable to minimise potential impacts on species of bird this would require the AC OHL to cross an RSPB reserve to the northeast of Tilbury. Consideration of the East Atlantic Flyway WHS nomination will also be required but as set out at Section 6.5 is not anticipated to modify the outcome informed by considerations SPA and similar designations.

13.2.13 Recognised mitigation measures for AC OHL impacts to bird assemblages would need to be used wherever appropriate. Mitigation for impacts of AC OHL prioritise eliminating exposure by undergrounding sections where there is a greater risk or routeing the AC OHL away from important bird areas. Secondary measures for reducing likely impacts to birds from AC OHL include installing bird diverters and embedding measures into the design (e.g., insulated components, greater air space between lines).

13.2.14 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitat and species Regulations 2017.

Physical environment

13.2.15 It is likely that a significant amount of development would be located within the floodplain. As flood water can ingress around pylon footprints this is unlikely to result in a significant effect once operational, however temporary impacts could arise where construction works are located within these zones.

13.2.16 Crossings of main rivers, Flood Zones 2 or 3 are likely to be unavoidable.

13.2.17 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

13.2.18 It is likely that a new substation at Bradwell could be located outside of flood zones 2 or 3.

13.2.19 Any extension to Tilbury substation would be within Flood Zone 3 therefore additional mitigation measures may be required.

13.3 Socio-economic appraisal

Settlements and populations

13.3.1 There are 22 main settlements within this study area and population density increases towards the south where it is likely that a new AC OHL would need to be routed near to settlements.

13.3.2 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 adverse visual effects which are set out in the landscape and visual appraisal.

Tourism and recreation

13.3.3 There are a number of NCNs routes within this study area. It is considered multiple cycle routes would be unavoidable within this option. There are also 27 Country Parks. These are found slightly more to the southern half of the study area with a cluster between Brentwood and Basildon.

13.3.4 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction, however this is likely to be the case with any option, and effects would be temporary. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN, and these effects would be permanent.

13.3.5 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route should part of a cycle route be closed during construction.

Land use

13.3.6 Grade 1 BMV land is located in the east of the study area. Grade 2 BMV land is fragmented throughout this study area. Grade 3 BMV agricultural land is prominent land type classification in the study area. Bramford Substation is located on Grade 2 BMV land. Loss of BMV likely to be limits for the OHL route but could be more significant where there are new substations.

13.3.7 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with pylon footprints but this is unlikely to be significant. Loss of BMV due to the substation should be avoidable. Other land uses are likely to be avoidable.

13.3.8 There is the potential to oversail a golf course, other land uses could be avoided by routeing where possible.

Infrastructure

13.3.9 The M25 motorway, A13, A1089, and A282 are located in the southwest corner of this study area. The A12 extends diagonally across the study area between Ipswich and Brentwood. The A120 extends across the study area in the north between Braintree and Harwich. The A14 extends around the urban settlement of Ipswich. It is considered that the A120 and A12 are unavoidable.

13.3.10 There are railway lines within this study area. Railway lines connect the urban settlements described above. It is considered at least three railway lines, and possibly more, would need to be crossed within this option.

13.3.11 Ten aerodromes are located within this study area, including Damyns Hall Aerodrome, Elsett, Essex Air Ambulance Airbase/Earls Colne Airfield, Great Oakley Airfield, London Southend Airfield, Napps Field, Stoke Golding Airfield, Stow Maries Aerodrome, Wattisham Airfield and an unnamed airfield located at Great Wakering. Ten ports and harbours area located within this study area including Chatham Docks, Cliff Quay, Harwich International Port, Ipswich Wet Dock, London Cruise Terminal, London Gateway Port, London Thamesport, Port of Felixstowe/Freightliner Terminal, Tilbury Docks, Town Pier. The locations of airfields and ports/harbours are considered avoidable.

13.3.12 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

13.3.13 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.

13.3.14 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

13.3.15 Routeing of a new AC OHL would have to take account of the ten 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.

13.4 Technical scope and costs

13.4.1 Technical analysis of option EAS 3 is as follows:

- This option to connect a 130km circuit between Bramford via New Bradwell Substation and Tilbury, takes energy south via a New Bradwell Substation to the existing substation at Tilbury.
- This option facilitates the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at a new Bradwell Substation point of connection.
- To make the connection to the New Bradwell substation at the old connection site would require crossing the river Blackwell at a distance of >5km. To make this crossing a river tunnel and cables would need to be used. This would add significant cost to this option with £200m of cable costs, for OHL options and >£100m tunnelling costs for all AC options.
- The existing Bradwell substation and the overhead line connecting to it are operate at 132kV. Both the substation and the circuit would need to be replaced by a substation and overhead line of 400kV capability with completely new infrastructure.

13.4.2 We undertake a cost evaluation of the following four technologies for onshore options evaluation.

a) 400 kV alternating current (AC) overhead line

b) 400 kV AC underground cable

c) 400 kV AC gas insulated line (GIL)

d) 525 kV high voltage direct current (HVDC) underground cable and converter stations

13.4.3 Option EAS 3 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, nine overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
  - The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, six overall, this cost is included in brackets () in the table.
  - Both HVDC options for this connection will be Three ended circuits with number HVDC convertor stations indicated above required at all three ends.
- **Substation works**
  - Extension to Bramford substation by 2 bays to accommodate new circuits.
  - New Bradwell Substation able to accommodate 12 bays.
  - Extension to Tilbury 400kV Substation by 2 bays to accommodate new circuits.

Table 13.1 – below sets out the capital costs for option EAS 3 considering substation works and each technology option.

Item	**Need**	**EAS 3 Capital Cost**			
Substation Works	Facilitate generation and connect new circuits	£141.3m			
New Circuits		**AC OHL**	**AC Cable**	**AC GIL**	**HVDC (Min 4000 MW rating)**
New Circuit 100 km	New Circuit across EC5 and LE1	£517.4	£5,610.8m	5,623.8m	£3,609.8m (£2,406.5m)
Total Capital Cost		**£658.7m**	**£5,752.1m**	**£5,765.1m**	**£3,751.m (£2,547.8m)**

13.4.4 Table 13.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 13.2 – EAS 3 Circuit Lifetime Cost Summary

Land Based option	EAS 3 AC OHL	EAS 3 AC Cable	EAS 3 AC GIL	EAS 3 HVDC (Min 4000 MW rating)
Capital Cost of New Circuits	£517.4m	£5,610.8m	£5,623.8m	£3,609.8m (£2,406.5m)
NPV of cost of losses over 40 years	£364.7m	£278.3m	£169.3m	£706.9m (£471.2m)
NPV of operation & maintenance costs over 40 years	£7.6m	£26.7m	£7.7m	£258.2m (£172.1)
Circuit Lifetime Cost of new circuits	**£890m**	**£5,916m**	**£5,801m**	**£4,575m (£3,050m)**

13.4.5 To make the connection at a new Bradwell substation would require crossing the River Blackwater with a minimum distance of 5km. A cable tunnel would need to be used. This would be significantly more costly (approximately £200m). The timescales likely to be required to consent, construct and commission tunnelling infrastructure would mean this option would not be deliverable by the required date in the need case.

13.4.6 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for EAS 3, 130 km connection between Bramford via New Bradwell Substation and Tilbury 400kV substations would be for an AC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

14. Offshore 1 – Norwich to Tilbury

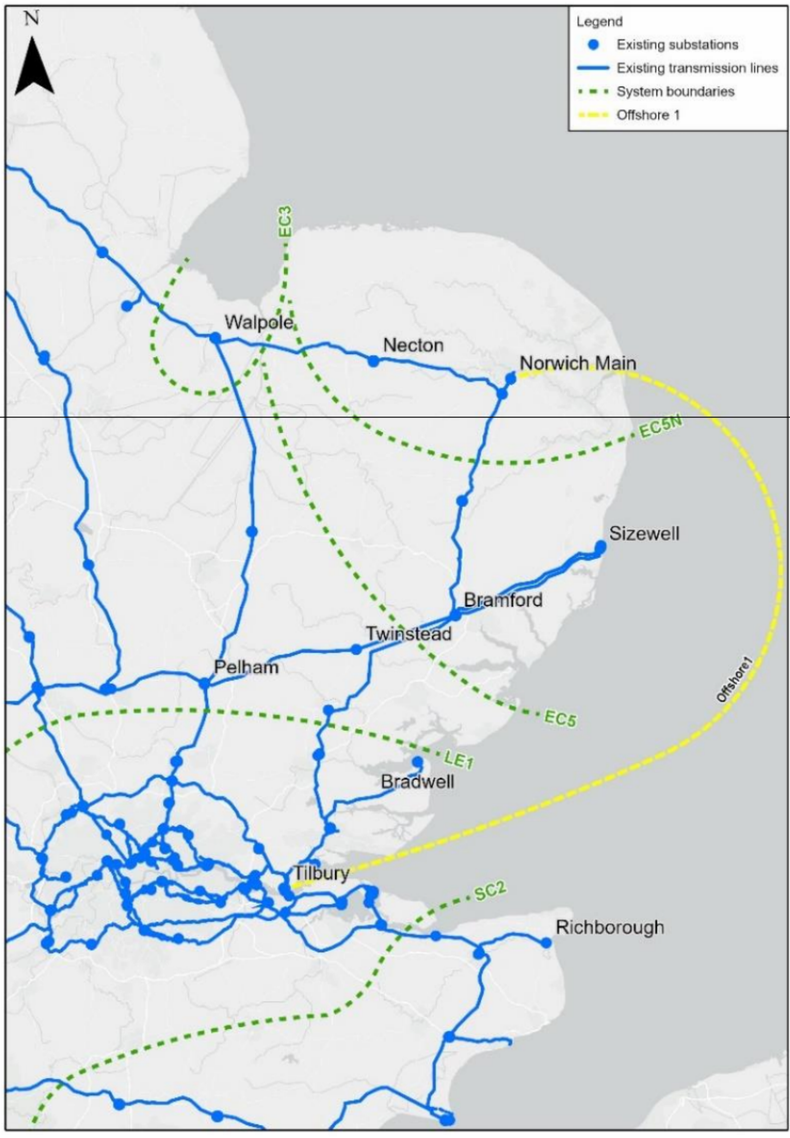
14.1 Introduction

14.1.1 Strategic option (SO) Offshore 1 involves a new offshore transmission connection between the existing substation at Norwich Main and the existing Tilbury substation, a distance of approximately 220 km. This option is shown in Figure 14.1.

14.1.2 This option could facilitate the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at offshore substations.

14.1.3 This option does not provide the flexibility of onshore connection options which facilitate flows both to the West and East of the transmission system for different system faults. This option only provides flows to the East of London, whereas energy demand is distributed throughout England so this option would not be as effective for all system conditions compared with the combination of an EAN and EAS option.

Figure 14.1 – Option Offshore 1 Norwich to Tilbury



14.2 Environmental appraisal

Landscape and visual

14.2.1 Two nationally designated landscapes are present in the study area, the Broads National Park and Suffolk Coast and Heaths AONB. Within the study area there would be very little opportunity to avoid both the National Park and AONB without the introduction of a longer onshore route.

14.2.2 The main constraint would be siting converter stations at Norwich near to The Broads National Park.

14.2.3 Converter Stations would present the only long-term adverse effect during operation.

14.2.4 This option has some constraints and would need to route/ site carefully through the areas near the Broads National Park and Suffolk Coast & Heaths AONB. Some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction which would reduce the potential for some visual effects. Some limited significant residual visual effects are possible.

Historic environment

14.2.5 Scheduled monuments are distributed throughout the study area and include sites dating from the prehistoric period onwards. While examples of scheduled monuments have been recorded throughout the study area, there are a number of areas where large scheduled monuments/concentrations of sites have been recorded. At the north end these include the remains of a Roman and medieval town on the south side of Norwich, near the Norwich Trowse and Norwich substation, as well as a cluster of medieval assets (including moated sites) in north Suffolk, and a focus near Great Yarmouth which includes the town walls.

14.2.6 Scheduled Monuments have been recorded around the Tilbury substation area.

14.2.7 Listed buildings have been recorded throughout the northern and southern landfall Options, with the vast majority being Grade II listed, although a relatively large number of Grade I and II* buildings have been recorded due to the size of the areas. These are mainly located within settlements scattered throughout the northern and southern landfalls, although Grade II listed buildings have also been recorded throughout the landscape.

14.2.8 A number of registered parks and gardens have also been recorded throughout the northern terrestrial study area, although no registered parks and gardens have been recorded in the southern section.

14.2.9 No registered battlefields have been recorded.

14.2.10 Although a review of non-designated assets was not undertaken as part of the current scheme, the Defence of Britain data set was examined and a large number of assets were recorded in the study area. These include a large concentration of defensive structures following along the coastline in both the north and south.

14.2.11 There are some protected wrecks in the study area including the South Edinburgh Channel and the London in the mouth of the Thames Estuary NE of Grain however these are likely to be avoidable through routeing.

14.2.12 It is likely that designated assets, such as scheduled monuments and listed buildings would 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.

14.2.13 Impacts on the setting of assets, where setting contributes to significance is likely to be limited to areas close to converter stations and the substation extensions.

Ecology

14.2.14 European and national designated sites are unlikely to be avoidable in particular at the landfalls at either end. Whilst effects arising from cable installation are likely to be temporary the potential for significant effect would depend on the habitat types that are present and their recoverability. Trenchless construction techniques could be used at landfalls to avoid direct effects on these designated sites, but these have technical limitations.

14.2.15 Onshore close to Norwich whilst designated sites maybe avoidable there is still the potential for effects associated with the interconnected habitats associated within the Broadland system.

14.2.16 The potential for a likely significant effect on these sites would need to be considered in relation to the Conservation of Habitats and Species Regulations 2017.

Physical environment

14.2.17 It is likely that a significant amount of onshore development would be located within the floodplain, whilst underground cable would not lead to any operation impacts, temporary impacts could arise where construction works are located within these zones.

14.2.18 Crossings of main rivers, Flood Zones 2 or 3 are likely to be unavoidable.

14.2.19 Significant operational effects are unlikely however a principal consideration is the management of construction works within Flood Zones 2 and 3.

14.2.20 Offshore the Thames estuary is a dynamic environment with sediment fluctuations. Kentish Flats, Gunfleet and Sunk Sand are areas of shallow water off the north Kent and Essex coasts. Any cable protection measures associated with cable or crossings of other infrastructure or any cable spanning within Kentish Flats and Gunfleet could result in an unacceptable reduction in water depth and an increased risk to shipping and navigation. Mobile sediment could also result in cable spanning or over burial of the cables.

14.2.21 Within the Thames estuary the deposition of large volumes of sediment during glacial times and its subsequent movement by the sea has created large features, such as sand banks and sandwave fields, which have a direct impact on the bathymetry profile of the Thames Estuary. The bathymetry in the Thames Estuary is dominated by the positions of the large sandbanks and the associated channels. The area is considered very active with continuing shifting/migration of the sand banks and channels.

14.2.22 The sandbanks comprise sands and muddy sands whilst in the channels the sediments can be very thin generally a few centimetres (cm) thick and comprise a veneer of gravel, sandy gravels and gravelly sands. The gravels generally comprise of flint or of calcareous concretions derived from the underlying London Clay. The underlying London Clay is present beneath the surficial sediments except where Quaternary infilled river channel deposits are present. The Eocene London Clay is comprised principally of stiff to very stiff marine silty clays, clayey and sandy silts with subordinate sands. The basal unit has hard cemented layers of argillaceous ash known as the Harwich Member.

14.3 Socio-economic appraisal

Settlements and populations

14.3.1 Temporary adverse impacts could arise if the underground cable route is situated within close proximity to settlements during construction associated with noise, air quality and construction traffic. There is the potential for adverse visual effects from the presence of converter stations which are set out in the landscape and visual appraisal.

Tourism and recreation

14.3.2 The Broads National Park lies within the northern onshore part of the study area this is unlikely to be avoidable without the introduction of a longer onshore route.

14.3.3 There are eight NCNs within this study area and are more prominent in the northern section. At least three national cycle routes would be unavoidable though it is considered that more would likely be unavoidable.

14.3.4 There are six Country Parks with four distributed through the northern onshore part of the study area and the remaining two to the south.

14.3.5 Routeing through the National Park should be avoided. This could be achieved through a longer onshore route.

14.3.6 There is the potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of NCN.

14.3.7 Standard best practice guidelines should be followed to provide appropriate signage, diversion routes and notice for the users of the cycle route should part of a cycle route be closed during construction.

Land use

14.3.8 It is considered Grade 1 BMV land is avoidable with careful routeing, however it is considered likely Grade 2 BMV land would be unavoidable.

14.3.9 There is the potential for temporary adverse impacts on agricultural land during construction. There is the potential for permanent loss associated with converter station siting, this should seek to avoid BMV land where possible. Other land uses are likely to be avoidable.

14.3.10 Consideration would need to be given to inshore fishing areas of importance via project specific consultation with fishermen once route selection process has been refined. Presence of rock placement can cause significant issues for bottom trawled gear in particular but it is not possible to clearly identify these areas at this stage.

14.3.11 There are a number of offshore mineral aggregate extraction areas located within the study area.

14.3.12 This option could result in disturbance to fisheries and reduction in access to fishing grounds-potential hazard from rock protection.

Infrastructure

14.3.13 There are multiple trunk roads within this study area, including the A249 in the south, A47 in the north. The A13 and A1089 are located in the northwest in the urban settlement Grays. The A249 is avoidable. There is the potential for the A47 to be crossed.

14.3.14 There are a number of railway lines within this study area. At least two railway lines would be unavoidable within this option.

14.3.15 Seething Airfield and Beccles Airfield are located in the north. It is considered the airports and ports are avoidable.

14.3.16 Where crossings are required, there is the potential for temporary closure of roads during construction. There is the potential for adverse visual effects which are set out in the landscape and visual appraisal on users of roads and railways.

14.3.17 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.

14.3.18 The route would have to pass over gas transmission pipelines, these areas could require additional cathodic protection methods.

14.3.19 Offshore there is a significant amount of infrastructure within the study area including numerous existing and proposed subsea cables/pipelines and offshore wind farms with associated substations and cables including Gridlink, NeuConnect and Britned interconnectors and potentially export cables from the Five Estuaries and North Falls OWFs, Nautilus and Lionlink (formerly Eurolink) proposed interconnectors and Greater Gabbard/Extension, Galloper/Extension, EA2, London Array and Kentish Flats OWFs.

14.3.20 Crossings with existing and proposed infrastructure would be required. Consideration would need to be given to the potential for an unacceptable reduction in water depth presenting a hazard to vessels in areas of shallow water. Additionally, crossings requiring rock protection within designated sites may present issues.

Shipping and navigation

14.3.21 The River Thames is a key navigation route supporting the passage of both freight and passenger shipping. Under the Port of London Act 1968 (as amended), PLA are responsible for maintaining and supervising navigation on the tidal River Thames from the lock gates at Teddington as far as the Thames Estuary where it meets the North Sea. The main navigational approaches through the Thames Estuary to the River Thames are along Princes Channel in the south and Black Deep and Barrow Deep to the north converging into the Yantlet Channel along the inner Thames Estuary and the River Thames. In the section between the Thames Estuary and Tilbury Substation over 10,000 ships per year are recorded to be transiting the Thames. The study area incorporates the SUNK TSS and is in the vicinity of the Harwich/Felixstowe dredged shipping Channel and other deep water navigation channels.

14.3.22 A number of channels including Yantlet are dredged for navigation to maintain an appropriate safe depth of water for navigation and this is likely to result in a significant constraint to cable routeing. Dredging would both pose a risk to the asset itself as well and safety concern for the dredging works. It is considered unlikely the PLA would grant consent for a River Works Licence for a cable route along a dredged shipping channel.

14.3.23 Either side of the main Yantlet channel are a number of anchorage areas and anchor berths. Anchorage areas would pose a risk to the asset itself from cable strike as well and safety concern for and vessels dropping their anchors. As the anchorage areas are fundamental to the operation of the major ports along the Thames It is considered unlikely the PLA would grant consent for a River Works Licence for a cable route that would impact on the operation of the anchorage areas or pose a safety risk.

14.3.24 The Thames Estuary is a dynamic environment and sediment levels within the estuary fluctuate which is one of the reasons some of the shipping channels needs to be dredged. As cable burial death is normally around a metre, however, a dynamic environment can lead to the cable becoming either exposed or buried deeper than the original installation depth. Should the cable before exposed remedial measures such as rock placement can be used to protect the asset. Should it become buried deeper there could be issues with heating which would affect the transmission capacity of the cable. Within the nearshore areas it is considered likely that any remedial rock placement would reduce the water depth and create an increased risk to shipping and navigation within these waters. As a result it is considered unlikely that the PLA would grant consent for a River Works Licence for a cable and protection measures that reduce the water depth in the nearshore shallow waters and may require re-burial in the future.

14.3.25 It is considered that shipping and navigation poses a significant constraint for the installation of a cable along the Thames Estuary to Tilbury due to the limited availability to avoid shipping channels, dredged shipping channels which would pose a risk and reauctions in water depth from remedial proception measures posing a risk to shipping and navigation.

14.3.26 There may be opportunities to mitigate the risk posed by Navigational issues and the regular dredging of shipping routes in the Thames Estuary such as deeper burial. These should be considered should a marine strategic option to Tilbury be selected as the preferred option.

14.4 Technical scope and costs

14.4.1 Technical analysis of option Offshore 1 is as follows:

- This option to connect a 220km offshore subsea circuit between Norwich via and Tilbury, takes energy south subsea to the existing substation at Tilbury.
- This option could facilitate the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation at offshore substation points of connection.
- This option does not provide the flexibility of onshore connection options which facilitate flows both to the West and East of the transmission system for different system faults. This option only provides flows to the East of London, whereas energy demand is distributed throughout England so this option would not be as effective for all system conditions compared with the combination of an EAN and EAS option.

14.4.2 We undertake a cost evaluation of the following four technologies for offshore options evaluation.

a) 400 kV AC Subsea cable

b) 525 kV high voltage direct current (HVDC) underground cable and converter stations

14.4.3 Option Offshore 1 requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6930 mega volt amperes (MVA) or;
  - HVDC using 525 kV 2000 MW voltage source links, which would require a convertor station at each end similar in size to a large warehouse. A 6000 MW connection would require three convertor stations at each end, seven overall, this is to come close to matching the AC hi-capacity circuits of 6930 MVA.
  - The original assessment minimum HVDC requirement to connect contracted generation, with no ability to accommodate future applications is 4000 MW capability requiring two convertor stations at each end, five overall, this cost is included in brackets () in the table.
  - One of the HVDC circuit for this connection will be Three ended with an additional HVDC convertor on offshore platform to facilitate generation connections.
- **Substation works**
  - Extension to Norwich substation by 2 bays to accommodate new circuits.
  - New Offshore Platform to facilitate connection of North Falls and Five Estuaries.
  - Extension to Tilbury 400kV Substation by 2 bays to accommodate new circuits.

Table 14.1 – below sets out the capital costs for option Offshore 1 considering substation works and each technology option.

Item	**Need**	**Offshore 1 Capital Cost**	
Substation Works	Facilitate generation and connect new circuits	£186.8m	
New Circuits		**AC Offshore Cable**	**Offshore HVDC (Min 4000 MW rating)**
New Circuit 220 km	New Circuit across EC5 and LE1	£9,501.8m	£3,909.7m (£2,695.6m)
Total Capital Cost		**£9,688.6m**	**£4,096.5m (£2,882.4)**

14.4.4 Table 14.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 14.2 – Offshore 1 Circuit Lifetime Cost Summary

Land Based option	**Offshore 1** **AC Offshore Cable**	**Offshore 1** **Offshore HVDC (min 4000 MW rating)**
Capital Cost of New Circuits	£9,501.8m	£3,909.7m (£2,695.6m)
NPV of cost of losses over 40 years	£476.0m	£549.8m (£392.7m)
NPV of operation & maintenance costs over 40 years	£45.2m	£201.8m (£144.1m)
Circuit Lifetime Cost of new circuits	**£10,023m**	**£4,661** **(£3,232m)**

14.4.5 From the environmental and technical appraisal considered, alongside capital and Circuit Lifetime Costs, the preferred option for Offshore 1, 220 km connection between Bramford and Tilbury 400kV substations by offshore connection, would be for a Subsea HVDC circuit connection. In light of this analysis, our starting presumption for further development of this option should it be selected, would be for a majority overhead line connection.

14.4.6 Should this circuit at full 6000 MW capacity made multiterminal to provide the same system flexibility as the AC circuit options. There would be a need for an additional three sets of HVDC convertor stations and three sets of 50km HVDC cable to connect to Bramford, to make multi-terminal HVDC links. This would add an additional £1,265.1m of capital cost and increase Circuit Lifetime Cost by £1,587m. This would give overall capital costs of £ 5361.1m (£4,096.5m + £1,265.1m), and overall Circuit Lifetime Cost of £6,248m (£4,661m + £1,587m).

15. Strategic options appraisal conclusions

15.1 Introduction

15.1.1 This Strategic Options Backcheck and Review has considered the following options:

Circuits to the North of East Anglia

- EAN 1 – Necton to Pelham 115km
- EAN 2 – Necton to Twinstead 90km
- EAN 3 – Necton to Bramford 85km
- EAN 4 – Norwich Main to Bramford 80km

Circuits to the South of East Anglia

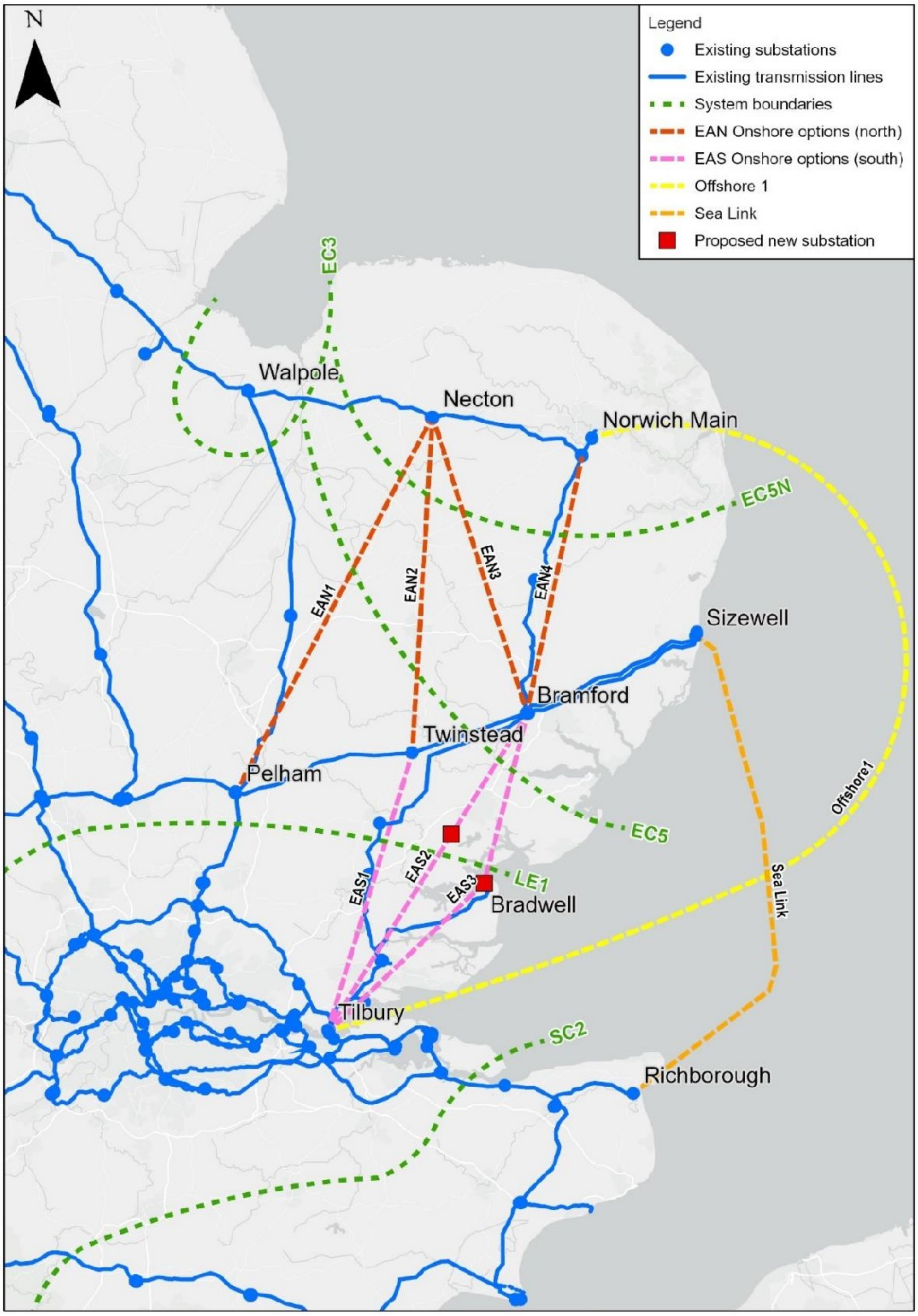
- EAS 1 – Twinstead to Tilbury 80km
- EAS 2 – Bramford via New Substation to Tilbury 100km
- EAS 3 – Bramford via New Substation at Bradwell to Tilbury 130km

Offshore Coastal East Anglia

- Offshore 1 – Norwich Main to Tilbury 220km

15.1.2 These are shown in Figure 15.1 below.

Figure 15.1 – options considered in this Strategic Options Backcheck and Review



15.1.3 A combination of the strategic options (set out in Table 15.1) are necessary for both onshore and offshore options. The table below sets out the combinations that are required and which boundary or group condition they support.

Table 15.1 – Combination of Options required to meet need

Boundary or Group	Onshore Options				Offshore
EC5N & EC3	EAN 1	EAN 2	EAN 3	EAN 4	Offshore 1
EC5 & LE1	EAS 1	EAS 2	EAS 3		
SC2, EC5, LE1 & Sizewell	Sea Link				

15.1.4 Any combination of one northern (EAN) and one southern (EAS) onshore options can be used to meet the need onshore, whilst Offshore 1 would be required to meet the need offshore. A Sea Link interactivity assessment is included in this document to show how it contributes 2000 MW of capacity to the SC2, EC5, LE1 and Sizewell generation group. The full Sea Link project is subject to its own option assessment.

15.1.5 As outlined in further detail in the previous sections, this backcheck and review considers for each option:

- environmental and socio-economic constraints;
- technology options available and the associated technical considerations; and
- the capital and Circuit Lifetime Costs of each technology option.

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

15.2 Environmental and socio-economic considerations

15.2.1 Tables 15.1 and Table 15.2 below summarise the environmental and socio-economic constraints for each option. Whilst all options would have impacts, none appear to present environmental issues that could not be mitigated with careful consideration of routeing and use of appropriate technologies and mitigation measures to specific constraints, as is consistent with the extant and emerging NPSs against which proposals for nationally significant infrastructure projects are assessed.

15.2.2 For northern onshore options, a principal consideration is the Breckland SPA/ SAC/SSSI complex. Whilst avoidable there is the potential for impacts on the interest features associated with both habitats and species. For the Offshore 1 option, European and national designated sites are unlikely to be avoidable, in particular at the landfalls at either end. Other considerations and potential impacts in the socio-economic assessment are broadly similar for all northern onshore options, with a variety of features present that would need to be avoided, or impact mitigation provided, for all of the options.

15.2.3 For all onshore options, overhead line options would generally be optimal given their lower cost and the ability to mitigate their impacts through careful routeing and design. A key consideration for southern onshore options is the Dedham Vale AONB, which – as discussed in further detail above – is within the study area for onshore options EAS 1, EAS 2 and EAS 3. In the case of EAS 1 it should be possible to avoid effects on the AONB through routeing. In the case of EAS2 and EAS3 the AONB could only be avoided with significantly longer routes.

15.2.4 In the case of option Offshore 1 there would be limited opportunity to avoid the Broads National Park and Suffolk Coast and Heaths AONB. However, some opportunities exist for mitigation through more detailed assessment, siting, routeing and construction which would reduce the potential for some visual effects. National Policy relating to electricity transmission networks is set out in National Policy Statements (NPS) EN-1 (2024) and EN-5 (2024), 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. EN1 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.

15.2.5 Paragraph 2.9.7 of EN-5 states that “While the Government does not believe that the development of overhead lines is incompatible in principle with applicants’ statutory duty under Schedule 9 of the Electricity Act 1989, to have regard to visual and landscape amenity and to reasonably mitigate possible impacts thereon, in practice new overhead lines can give rise to adverse landscape and visual impacts.” Paragraph 2.9.20 states that “Although it is the government’s position that overhead lines should be the strong starting presumption for electricity networks developments in general, this presumption is reversed when proposed developments will cross part of a nationally designated landscape (i.e. National Park, The Broads, or Areas of Outstanding Natural Beauty).” Paragraph 2.9.22 goes on to state that “However, undergrounding will not be required where it is infeasible in engineering terms, or where the harm that it causes is not outweighed by its corresponding landscape, visual amenity and natural beauty benefits. Regardless of the option, the scheme through its design, delivery, and operation, should seek to further the statutory purposes of the designated landscape...” Paragraph 2.9.23 states that cases will arise where – though no part of the proposed development crosses a designated landscape – a high potential for widespread and significant adverse landscape and/or visual impacts along certain sections of its route may result in recommendations to use undergrounding for relevant segments of the line or alternatively consideration of using a route including subsea cabling. In these cases, Paragraph 2.9.24 states that ...”the Secretary of State must weigh the feasibility, cost and any harm of the undergrounding or subsea option against: .

- The adverse implications of the overhead line proposal;

- The cost and feasibility of re-routing overhead lines or mitigation proposals for the relevant line section; and
- The cost and feasibility of the reconfiguration, rationalisation, and/or use of the underground or subsea cabling of proximate existing or proposed electricity networks infrastructure."

15.2.6 As noted in the assessments above, it would be possible to avoid some potential adverse effects of options EAS 2 and EAS 3 on the landscape and visual amenity of the Dedham Vale AONB and South Suffolk and North Essex Claylands NCA. However, it is unlikely that all of the impacts could easily be mitigated. Significant residual effects are therefore possible. Given the significantly greater length required to avoid the AONB, it is likely that these options would require undergrounding in the AONB.

Table 15.2 – Environmental appraisal (topics)

Option	Landscape and visual	Historic Environment	Ecology	Physical Environment
EAN1	- Likely significant residual effects are possible for residents and Registered Parks and Gardens. - Moderately to heavily constrained - It may be challenging to find a route which achieves a parallel alignment.	- A relatively large number of non-designated assets were recorded in the study area. - Designated assets are likely to be avoidable, due to the linear nature of some designated scheduled monuments avoidance is likely to introduce multiple angles to an AC OHL route. - There is the potential for significant impacts on the setting	- A principal consideration is the Breckland SPA/ SAC/SSSI complex. Whilst avoidable there is the potential for impacts on the interest features of both habitats and species. - Routeing would need to consider bird flight paths	- Would have to cross several unavoidable watercourses and that of its floodplains. - Given the extent of Flood Zones 2 & 3, it is likely that a significant amount of development would be within the floodplain.
EAN2	- The central part of the study area has a cluster of sensitive receptors; it may be challenging to find a direct route without additional mitigation. - Some significant residual effects are possible for residents - Moderately constrained - This option would not offer any close parallel opportunities	- Many military defences have been recorded; these appear to represent parts of "Stop Lines" constructed during the Second World War - Potential for significant impacts on the setting of high value designated assets	- Statutory designated sites for nature conservation are likely to be avoidable - Breckland SPA/SAC/SSSI complex is located within the western half of the study area, this would require an increased length of AC OHL - Routeing would need to consider bird flight paths	- Would have to cross over several unavoidable watercourses and associated flood zones - Likely that a significant amount of development would be within the floodplain. - Crossings of main rivers are likely to be unavoidable

Option	Landscape and visual	Historic Environment	Ecology	Physical Environment
EAN3	- Some significant residual effects are possible for residents -Moderately constrained	- There are several areas where large concentrations of sites have been recorded - Large number of Grade I and II* buildings have been recorded - Potential for significant impacts on the setting, of high value designated assets identified	- Principal consideration is the Breckland SPA/SAC/SSSI complex which is located within the northwest	- Crossings of main rivers, Flood Zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable
EAN4	- Limited constraints	- Potential for significant impacts on the setting, with many high value designated assets identified	- There is one European site within the study area	- Would have to cross over several unavoidable watercourses and associated flood zones - Crossings of main rivers, Flood Zone 2 or 3 and Source Protection Zone 3 are likely to be unavoidable
EAS1	- One nationally designated landscape, the Dedham Vale AONB - Moderately to heavily constrained	- Military defences have also been identified throughout the option, with a significant cluster to the south	- Routeing would need to consider bird flight paths	- Likely that a significant amount of development would be located within the floodplain - Crossings of main rivers, Flood Zones 2 or 3 are unlikely to be avoidable
EAS2	- Much of the study area comprises constraints, it is unlikely that all of the impacts could easily be mitigated	- Parks and Gardens and scheduled monuments are distributed throughout	- Routeing would need to consider bird flight paths	- Likely that a significant amount of development would be located within the floodplain

Option	Landscape and visual	Historic Environment	Ecology	Physical Environment
	- Would require a significantly longer AC OHL to avoid Dedham Vale AONB - Likely to require at least 5km of undergrounding -Significantly constrained	- Potential for significant impacts on the setting of the value designated assets identified		- Crossings of main rivers, Flood Zones 2 or 3 are unlikely to be avoidable - Any extension to Tilbury substation would be within Flood Zone 3 and additional mitigation measures may be required
EAS3	- Would require a significantly longer AC OHL to avoid Dedham Vale AONB - Likely to require at least 5km of undergrounding -Significantly constrained	- Two extensive Parks and Gardens occupy a large area of land near -Potential for significant impacts on the setting of the value designated assets identified	- Routeing would need to consider bird flight paths	- Likely that a significant amount of development would be located within the floodplain - Crossings of main rivers, Flood Zones 2 or 3 are unlikely to be avoidable
Offshore 1	- Very little opportunity to avoid both the National Park and AONB - The main constraint would be siting converter stations	- Large number of Grade I and II* buildings have been recorded - Some protected wrecks in the study	- European and national designated sites are unlikely to be avoidable in particular at the landfalls at either end of option	- Likely that a significant amount of development would be located within the floodplain - The bathymetry in the Thames Estuary is dominated by the positions of large sandbanks and associated channels. The area is very active with shifting/migration of the sand banks and channels

Table 15.3 – Socio-economic appraisal (topics)

Option	Settlements and populations	Tourism and recreation	Land use	Infrastructure
EAN1	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction	- Grade 2 BMV land is scattered throughout this study area and is considered unavoidable - Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprints	- The A14 extends across the study are, this would be unavoidable. - The M11 and A11 would need to be crossed within this study area. - At least three railway lines would need to be crossed - Route would pass over gas transmission pipelines
EAN2	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- At least four NCN's are unavoidable - Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction	- Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprint unlikely to be significant	- At least two railway lines are unavoidable - Route would pass over gas transmission pipelines - Routeing of a new AC OHL would have to take account of the four aerodromes

Option	Settlements and populations	Tourism and recreation	Land use	Infrastructure
EAN3	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction	- Grade 2 BMV land is scattered throughout this study area and is considered unavoidable - Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprint unlikely to be significant	- The A11 and A14 are unavoidable - At least two railway lines are unavoidable - Route would pass over gas transmission pipelines - Routeing of a new AC OHL would have to take account of the nine aerodromes
EAN4	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction	- Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprint unlikely to be significant	-The A14 is unavoidable - At least one railway line is unavoidable -Route would pass over gas transmission pipelines - Routeing of a new AC OHL would have to take account of the three aerodromes

	Settlements and populations	Settlements and populations	Settlements and populations	Settlements and populations
EAS1	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- At least three NCN's are unavoidable - Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction -15 country parks within the study area	- Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprint unlikely to be significant	- The A120 and A12 are unavoidable - A number of railway lines extend across the entire reach of the study area and which are therefore unavoidable -Route would pass over gas transmission pipelines - Routeing of a new AC OHL would have to take account of the four aerodromes
EAS2	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- Multiple cycle routes would be unavoidable within this option. - Potential for temporary adverse effects associated with severance should cycle routes need to be temporarily closed during construction - 27 country parks within study area	- Bramford Substation is located on Grade 2 BMV land - Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with pylon footprint unlikely to be significant	- The A120 and A12 are unavoidable - At least three railway lines would need to be crossed - Routeing of a new AC OHL would have to take account of the ten aerodromes - Route would pass over gas transmission pipelines

	Settlements and populations	Settlements and populations	Settlements and populations	Settlements and populations
EAS3	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- Multiple cycle routes would be unavoidable within this option. - 27 country parks within study area	- Bramford Substation is located on Grade 2 BMV land. - Potential for temporary adverse impacts on agricultural land during construction. - Potential for permanent loss associated with pylon footprint unlikely to be significant	- The A120 and A12 are unavoidable - At least three railway lines would need to be crossed - Routeing of a new AC OHL would have to take account of the ten aerodromes - Route would pass over gas transmission pipelines
Offshore 1	- Temporary adverse impacts could arise if the AC OHL is situated within proximity to settlements during construction	- At least three national cycle routes would be unavoidable - 6 country parks within study area	- Likely Grade 2 BMV land would be unavoidable - Potential for temporary adverse impacts on agricultural land during construction - Potential for permanent loss associated with converter station siting. - Number of offshore mineral aggregate extraction locations within study area - Could result in disturbance to fisheries and reduction in access to fishing grounds-potential hazard from rock protection	- At least two railway lines would be unavoidable - Route would pass over gas transmission pipelines - Offshore there is a significant amount of infrastructure - Consideration would need to be given to the potential for an unacceptable reduction in water depth presenting a hazard to vessels in areas of shallow water

15.3 Technical considerations

15.3.1 Four onshore technology options were considered for the potential connections. There is extensive operational experience of both overhead lines and underground cables but limited experience of GIL and onshore HVDC for the connection distances considered.

15.3.2 Two offshore technologies were considered for potential connections. There is more operational experience of offshore HVDC systems, but there is limited experience of 400kV AC subsea cable installation and operation for the connection distances considered.

15.3.3 The strategic options have been assessed as to whether they offer any major additional system benefits for the transmission system beyond meeting the identified reinforcement need. Such benefits are considered because some degree of extra capacity may negate the need for further reinforcement works soon.

15.3.4 The onshore options provide additional system flexibility by connecting into the main transmission system between the northern and southern options. This allows better power flows when faults or maintenance occur as more routes are available than for options which cross all the boundaries without intermediate connections.

15.3.5 Of the southern onshore options, all options offer the ability to connect the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation. However, EAS 2 and EAS 3 do so without requiring the generators to build a significant amount of further infrastructure to connect much further inland. These options allow the opportunity to construct a new substation in the vicinity of the coast to facilitate these connections and have sufficient capacity to accommodate any further future connections from costal generation and interconnectors.

15.3.6 A proposed new small demand substation in the vicinity of Twinstead Tee is currently also included in the Bramford to Twinstead connection project, for which development consent is currently being sought. Option EAS 1 would require a complete re-design of Twinstead substation from that proposed, significantly increasing its size and land required. Furthermore, to ensure circuit continuity across EC5 boundary is maintained for a Bramford to Pelham fault, an EAN 4 and EAS 1 combination of options would require the turn-in of the Bramford to Braintree circuits to the new substation. This may require the substation location to be re-considered altogether with additional cost and complexity to this proposal.

15.3.7 Both the re-design and additional circuit turn-in would cause delays in consequence to the Bramford to Twinstead project would lead to significant constraint cost increases borne by consumers in the order of £500m or greater.

15.4 Cost considerations

15.4.1 Table 15.4 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 15.4 – Cost Summary of combination of works required to meet project need

Boundary or Group	Onshore Options				Offshore
EC5N & EC3	EAN 1 Necton to Pelham	EAN 2 Necton to Twinstead	EAN 3 Necton to Bramford	EAN 4 Norwich Main to Bramford	Offshore 1 Norwich Main to Tilbury
Economic Technology (Capacity)	OHL 115km (6930 MW)	OHL 90km (6930 MW)	OHL 85km (6930 MW)	OHL 80km (6930 MW)	
Capital Cost including non-circuit works	£494.5m	£494.2m	£375.1m	£355.2m	
Circuit 40yr Lifetime NPV Cost	£787m	£616m	£582m	£548m	
EC5 & LE1	EAS 1 Twinstead to Tilbury	EAS 2 Bramford via new substation to Tilbury	EAS 3 Bramford via Bradwell to Tilbury		
Economic Technology (Capacity)	OHL 80km (6930 MW)	OHL 100km (6930 MW)	OHL 130km (6930 MW)		HVDC 220km (6000 MW) [4000 MW]
Capital Cost including non-circuit works	£454.4m	£539.3m	£658.7m		£4,096.5 [£2,882.4m]
Circuit 40yr Lifetime NPV Cost	£548m	£684m	£890m		£4,661m [£3,232m]
SC2, EC5, LE1 & Sizewell	Sea Link Sizewell area to Richborough area				
Economic Technology (Capacity)	HVDC 145km 2000 MW				
Capital Cost including non-circuit works	£1,420.8m				
Circuit 40yr Lifetime NPV Cost	£1,197m				

15.4.2 To meet the need case of providing 9,225 MW across EC5 , both the AC onshore options (with a capacity of 6,930 MW) and HVDC option Offshore 1 (6,000 MW) would meet the need set out earlier in this document in combination with the 2,000 MW SCD1/Sea Link or an equivalent along with power flow control to manage 300MW shortfall. A 4000 MW HVDC option was included for completeness based upon earlier contracted backgrounds which are no longer current and no longer meet the need.

15.4.3 The lowest overall onshore cost combination to meet the need as indicated in Table 15.4 is:

- EAN 4 – Norwich Main to Bramford with capital costs of £355m and Circuit Lifetime Costs of £548m; and
- EAS 1 – Twinstead to Tilbury with a capital costs of £454m and Circuit Lifetime Costs of £547m.

15.4.4 The total capital cost would therefore be £809m, with circuit lifetime cost of £1,095m.

15.4.5 However, only the EAS 1 option facilitates the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation, with a combined capacity of 3580 MW, with the significant cost of bringing these coastal connections much further inland and providing connections at a new Twinstead substation.

15.4.6 The EAS 1 option also does not easily facilitate any future coastal generation and interconnector connections for which solutions providing >6000 MW capacity could accommodate by their inherent additional capacity to support delivering net zero by 2050.

15.4.7 As mentioned above, of the southern onshore options, only EAS 2 and EAS 3 provide the ability to the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation by allowing for a new coastal substation.

15.4.8 EAS 1 would result in additional costs of £500m or greater, to carry out the necessary transmission connection works for the interconnectors and generators to connect much further from the coast. This cost would be significantly greater than the £85m capital differential to the next least cost option southern onshore option (EAS 2), which includes the cost for a new substation for these generation connections.

15.4.9 Option EAS1 would require rebuilding of Twinstead substation and depending on the northern option selected would require the turn-in of Bramford-Braintree circuits into Twinstead.

15.4.10 These factors make EAS1 less optimal from a technical perspective and additional costs both in delays of existing projects and additional customer connection costs would make the overall cost impact of this option less favourable as well as the need for a significantly large new substation to be constructed.

15.4.11 Therefore, taking into account environmental, socio-economic, net zero government obligations, technical and cost perspectives, the optimal overall onshore combination to meet the need and facilitate the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation is:

- EAN 4 – Norwich Main to Bramford with capital costs of £355m and Circuit Lifetime Costs of £548m; and
- EAS 2 – Bramford via a new coastal substation to Tilbury with capital costs of £539.3m and Circuit Lifetime Costs of £684m.

15.4.12 The total capital costs would therefore be £894m, with Circuit Lifetime Costs of £1,232m.

15.4.13 Although it would be challenging to avoid altogether impacts on the Dedham Vale AONB as a result of EAS 2, this is not considered to be inconsistent with policy in the two relevant NPSs as outlined above. If routeing to avoid the AONB is not considered viable, it would be possible to use underground cables, as anticipated in Government policy.

15.4.14 Originally, the lowest cost offshore alternative option to meet the need was option Offshore 1 (Norwich Main to Tilbury) at 4000 MW with capital costs £2,882.2m and Circuit Lifetime Costs of £3,232m, in combination with SCD1/Sea Link or an alternative. However, this option no longer provides the required capacity of a minimum of 8,000 MW across LE1 and EC5, since the updated contracted generation described in the needs case section of this report has increased. This option has been included in this report as it was considered when the contracted position allowed and disclosed previously. Option Offshore 1 is also suboptimal in technical terms relative to the optimal onshore combination of options (EAN 4 and EAN 2).

15.4.15 The offshore alternative to match the capacity of AC onshore options is a Norwich Main to Tilbury 6000 MW option, which, when combined with Sea Link, would meet the requirements of delivering 8,000 MW across EC5 and LE1 by 2050. The capital costs would be £4,097m and Circuit Lifetime Costs £4,661m, significantly in excess of the costs of onshore combinations. Option Offshore 1 is also suboptimal in technical terms relative to the optimal onshore combination of options (EAN 4 and EAN 2).

15.4.16 As noted above, the 6,000 MW Offshore Option 1 would facilitate the connection of the contracted Essex Cost Generation Group including Tarchon Interconnector, North Falls and Five Estuary offshore wind generation with a combined capacity of 3,580MW. However, to make an offshore connection into the link would require the additional cost of HVDC converter station, AC substation, offshore HVDC platform, Offshore AC platform with an additional capital cost of greater than £500m.

15.4.17 Offshore options do not provide the flexibility of onshore connection options which facilitate flows both to the West and East of the transmission system for different system faults. Offshore 1 only provides flows to the East of London, whereas energy demand is distributed throughout England so this option would not be as effective for all system conditions compared with the combination of an EAN and EAS option.

15.4.18 Furthermore, the Offshore 1 option would not provide comparable capability to the AC onshore combinations. To achieve a fully like-for-like alternative with the AC North and South of East Anglia circuit options, with the additional flexibility of connecting into Bramford or substations to the west, the HVDC solution would need to be of a multi-terminal design, with 3 additional 2000 MW converters located at Bramford and cabling 50km from a DC bussing point offshore. This would significantly increase the costs and the potential environmental effects.

16. Interaction with other projects

16.1.1 As stated in Section 6, Strategic Options Overview, a further consideration NGET is currently evaluating is the interaction of both onshore and offshore options with Sea Link (SCD1). Sea Link is a 2000 MW HVDC connection from Sizewell to Richborough, with a proceed signal and 'HND critical' status in the NOA process.

16.1.2 Sea Link will be subject to its own full strategic options appraisal process. However, the presence or otherwise of a 2000 MW connection in the Sizewell area has a significant impact upon what is required to be built in the East Anglia region. For instance, if Sea Link, or an alternative with similar capacity, does not connect in the Sizewell area, there would be a requirement for additional infrastructure to accommodate the needs of the Sizewell generation group, as identified in Section 3.

16.1.3 Due to the interrelation between these projects, this report has undertaken an interactivity assessment of Sea Link.

16.1.4 This interactivity assessment sets out a comparison of the Sea Link options compared with the costs for an OHL providing the solution to the same need case.

16.1.5 This interactivity assessment also aims to present how the interaction of Sea Link and the strategic options set out in this report can impact upon the required amount of infrastructure needed in the immediate future.

16.1.6 Technical analysis of Interaction with Sea Link is as follows:

16.2 Technical scope and costs

16.2.1 As point of comparison to resolve the specific interconnector transfer requirements Sea Link HVDC option only requires 2000 MW of capacity. The AC onshore options would require a minimum of Med Capacity 6380MVA as AC flows cannot be controlled and more power will flow down these circuits under certain conditions. The AC subsea cable will therefore use this Med Capacity and for a point of comparison the onshore AC OHL required to allow the transfer between Sizewell and Canterbury 265km has also been included.

a) 400kV Overhead line

b) 400 kV AC Subsea cable

c) 525 kV high voltage direct current (HVDC) underground cable and converter stations

16.2.2 The interactive Sea Link project requires the following transmission works to satisfy the requirements of the SQSS.

- **New circuit requirements**
  - AC connections options use hi-capacity double circuits (two 400 kV AC circuits) with a total capacity of up to 6380 mega volt amperes (MVA) or;

— HVDC using 525 kV 2000 MW voltage source link, which would require a convertor station at each end similar in size to a large warehouse. A 2000 MW connection would require one convertor stations at each end, this is to provide the identified interactive need between East Anglia and Kent transmissions Systems

- **Substation works**

  — Substation connections to Friston/Sizewell

  — Remote HVDC Convertor Connection Cost (HVDC only)

  — Connection to New Substation between Richborough and Canterbury, along with associated circuit uprating works

Figure 16.1 – Option Sea Link Sizewell to Richborough

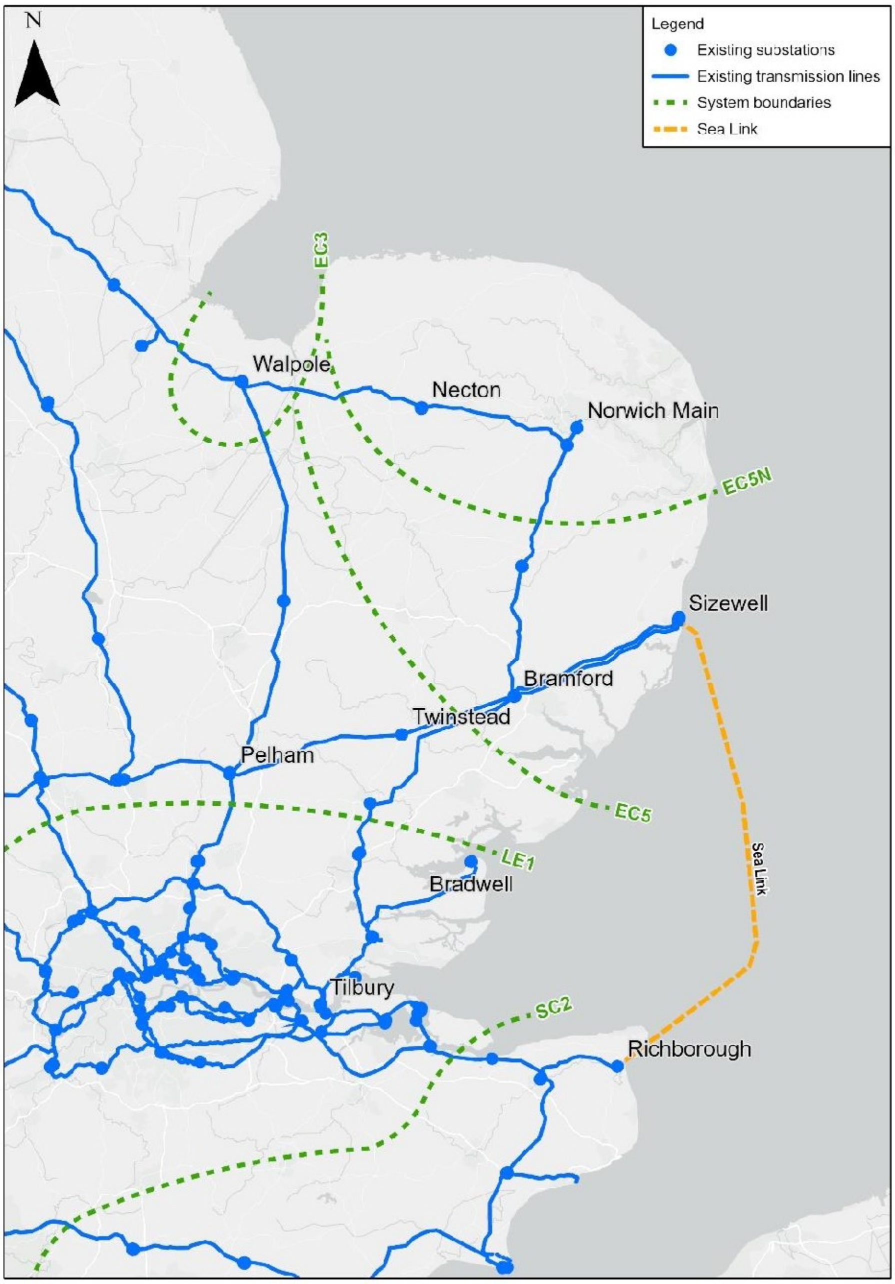


Table 16.1 below sets out the capital costs to show comparison of interactive Sea Link scheme compared to an onshore alternative considering substation works and each technology option.

Table 16.1 – capital costs of Sea Link options

Item	**Need**	**Sea Link Interaction Capital Cost**		
Substation Works	Facilitate generation and connect new circuits	£160m		£438.4m
New Circuits		**AC Onshore OHL**	**AC Subsea Cable**	**Offshore HVDC**
New Circuit Subsea 145km Onshore 165km	New Circuit across EC5 and LE1	£964.6m	£4,406.4m	£982.4m
Total Capital Cost	**£4,566.4m**		**£4,566.4m**	**£1,420.8m**

16.2.3 Table 16.2 below sets out the Circuit Lifetime Cost for the new circuit options, the Circuit 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 16.2 – Circuit Lifetime Costs of Sea Link options

Land Based option	**AC Onshore OHL**	**AC Subsea Cable**	**HVDC**
Capital Cost of New Circuits	£964.6m	£4,406.4m	£982.4m
NPV of cost of losses over 40 years	£828.1m	£280.2m	£157.1m
NPV of operation & maintenance costs over 40 years	£15.5m	£25.3m	£57.5m
Circuit Lifetime Cost of new circuits	**£1,808m**	**£4,712m**	£1,197m

16.2.4 The interactivity assessment of Sea Link shows that for an onshore option in this case to deliver the same system requirements as the proposed HVDC option, the capital costs would be closely equivalent and the Circuit Lifetime Cost of the onshore option would be significantly higher.

16.2.5 The onshore option also will have to not only approach urban areas of London where construction would be complex but would also have to cross the River Thames at a wide part of the Estuary. This would add significant cost to this option as such a crossing would likely require a cable tunnel with the additional cost of cable and tunnel excavation.

16.2.6 Therefore, whilst Sea Link has been subject to a separate strategic options exercise and Strategic Option Report published October 2023, the outcome of the interactivity assessment is a provisional recommendation that the assumption that Sea Link (or an equivalent) will provide 2000 MW of offshore capacity to Sizewell – as per the conclusions of the CPRSS – is sound for the purposes of this Strategic Options Backcheck and Review exercise.

17. Conclusion and next steps

17.1 Interim conclusions

17.1.1 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.

17.1.2 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.

17.1.3 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 revised National Policy Statements EN-1, EN-3 and EN-5.

17.1.4 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 an interim preference of the onshore combination of **EAN 4 OHL Norwich Main to Bramford** and **EAS 2 OHL Bramford via a new substation to Tilbury**, alongside SCD1/Sea Link or an alternative connection from Sizewell area to north Kent. We will continue to review our work including in light of changes in circumstances and we will have regard to consultation responses.

17.1.5 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 including in light of changes in circumstances and we will have regard to consultation responses.

17.1.6 The interim preference onshore combination of EAN 4, EAS 2 and Sea Link resolves the needs case set out below.

- Provision of 9,225 MW of capacity across East Anglia EC5 Boundary and 4,931 MW of capacity across EC5N Boundary.
- Provision of 7,476 MW of capacity across the LE1 Boundary.
- Provision of 1,852 MW from the Sizewell Generation Group.
- Provision of 3,480 MW of connection capacity for the Essex Coast Generation Group
- Provision of 1,800 MW of capacity from the SC2 Boundary Group.

17.1.7 The project was formerly known as East Anglia Green Energy Enablement (GREEN). We've changed the name to Norwich to Tilbury make it clear that this project is part of The Great Grid Upgrade, the largest overhaul of the grid in generations.

17.2 Next steps

17.2.1 Norwich to Tilbury will now be taken forward to the next stage of development, statutory consultation, to seek feedback from consultees and help shape the further development of the projects prior to an application for a Development Consent Order being made in 2025.

17.2.2 More detailed analysis for SCD1 Sea Link will be carried out separately and will come forward for consultation in in due course.

Appendices

Appendix A: Summary of National Grid Electricity Transmission legal obligations

Appendix B: Requirement for development consent

Appendix C: Technology overview

Appendix D: Economic appraisal

Appendix E: Mathematical principles used for AC loss calculation

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nationalgrid

Appendix A
Summary of National Grid Electricity Transmission Legal Obligations

A.1 Electricity Transmission Licence

A.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’).

A.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.

A.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.

A.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.

A.2 Electricity Act Duties

A.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.

A.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".

A.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.

A.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.

A.3 National Grid's Transmission Licence Requirements

A.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).

A.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.

A.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).

A.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.

A.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.

Appendix B
Requirement for Development Consent Order

B.1 Electricity Network Infrastructure Developments

B.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.

B.1.2 The Planning Act 2008 defines developments of new electricity overhead lines of 132kV 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.

B.1.3 Five National Policy Statements ("NPS") for energy infrastructure were designated by the Secretary of State for Energy and Climate Change in November 2023 and confirmed by parliament in January 2024. 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. The current nuclear National Policy Statement (NPS), EN-6, was published in 2011 and provides a framework for assessing development consent applications for new nuclear power stations expected to deploy by the end of 2025.

B.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.

B.2 Demonstrating the Need for a Project

B.2.1 Part 3 of EN-1 sets out Government policy on the need for new nationally significant energy infrastructure ////projects. Paragraph 3.3.1 states that electricity meets a significant proportion of our overall energy needs and our reliance on it will increase as we transition the energy system to deliver net zero.

B.2.2 3.3.4 states that there are several different types of electricity infrastructure that are needed to deliver the UK's energy objectives. These include "Additional generating plants, electricity storage, interconnectors and electricity networks all have a role, but none of them will enable us to meet thes objectives in isolation."

B.2.3 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 (2011).

B.2.4 The need for new transmission infrastructure for this project is described in section 3 of this Report.

B.3 Assessment Principles Applied by Decision Maker

B.3.1 Part 4 of EN-1 sets out the general policies that are applied in determining DCO applications relating to new energy infrastructure. -Section 2.9 EN-5 set out the general assessment principles in the specific context of electricity networks infrastructure.

B.3.2 Principles of particular importance for transmission infrastructure projects include:

B.3.3 Presumption in Favour of Development

- Section 4.1 of EN-1 states that given the level and urgency of need for infrastructure (of the types covered by EN-1), the Secretary of State will start r 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 Secretary of State should take account of potential:
  - benefits (e.g. the contribution to meeting the need for energy infrastructure, job creation and long-term or wider benefits), and
  - adverse impacts (e.g. long term and cumulative impacts but taking into account proposed mitigation measures.

B.3.4 Consideration of Alternatives

- Section 4.3 of EN-1 states that, as in any planning case, the relevance or otherwise to the decision making process of the existence (or alleged existence) of alternatives to the proposed development is, in the first instance, a matter of law. NPS EN-1 does not contain any general requirement to consider alternatives or to establish whether the proposed project represents the best option from a policy perspective. However, in relation to electricity transmission projects, paragraph 29.14 of EN-5 states that, "where the nature or proposed route of an overhead line proposal makes it likely that its landscape and visual impacts 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 4.3 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[7] and requirements in relation to compulsory acquisition.

B.3.5 Adverse Impacts and Potential Benefits

- Part 5 of EN-1 covers the impacts that are common across all energy NSIPs and section 2.- 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

[7] 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.

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:

B.3.6 Good Design

- Section 4.7 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 2.4 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.

B.3.7 Climate Change

- Section 4.10 of EN-1 explains how the effects of climate change should be taken into account and section 2.3 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 and storms on overhead lines, higher average temperatures leading to increased transmission losses and earth movement or subsidence caused by flooding or drought (for underground cables).

B.3.8 Holistic Planning

- Section 4.10 of EN1 and Section 2.7 of EN-5 explains that the Planning Act 2008 aims to create a holistic planning regime, such that the cumulative effects of the same project can be considered together. Accordingly, the government envisages that, wherever reasonably possible, applications for new generating stations and their related infrastructure should be contained in a single application. Paragraph 2.7.2 goes onto state that a consolidated approach of this kind may not always be possible, nor represent the most efficient strategy for delivery of new infrastructure. -.

B.3.9 Electricity Act Duties

- Paragraph 2.2.10 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. Paragraph 2.8.5 sets out that transmission operators (and Distribution Network Operators) are also required to facilitate competition and so provide a connection where requested.

B.3.10 Adverse Impacts and Potential Benefits

- Part 5 of EN-1 covers the impacts that are common across all energy NSIPs and section2.-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 2.9.7 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 Schedule 9 to the Electricity Act 1989, to have regard to visual and landscape amenity and to reasonably mitigate possible impacts thereon. 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 undergrounding and subsea cables, paragraph 2.9.20 states “Although it is the government’s position that overhead lines should be the strong starting presumption for electricity networks developments in general, this presumption is reversed when proposed developments will cross part of a nationally designated landscape (i.e. National Park, The Broads, or Areas of Outstanding Natural Beauty.” However, paragraph 2.9.22 goes onto state that undergrounding will not be required where it is infeasible in engineering terms, or where the harm that it causes is out outweighed by its corresponding landscape, visual amenity and natural beauty benefits. -Taking account of the fact that Government has not laid down any further rule on the circumstances requiring the use of underground or subsea cables, the Secretary of State much weigh the feasibility, cost, and any harm of the undergrounding or subsea option against:
- The adverse implications of the overhead line proposal;
- The cost and feasibility of re-reouting;
- Cost and feasibility of the reconfiguration, rationalisation, and/or use of underground or subsea cabling of proximate existing or proposed electricity network infrastructure.
  - Paragraph 2.9.17 of EN-5 endorses the Holford Rules which are a set of "common sense" guidelines for routeing new overhead lines.

Appendix C
Technology Overview

C.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.

C.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.

C.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.

C.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.

C.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).

C.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.

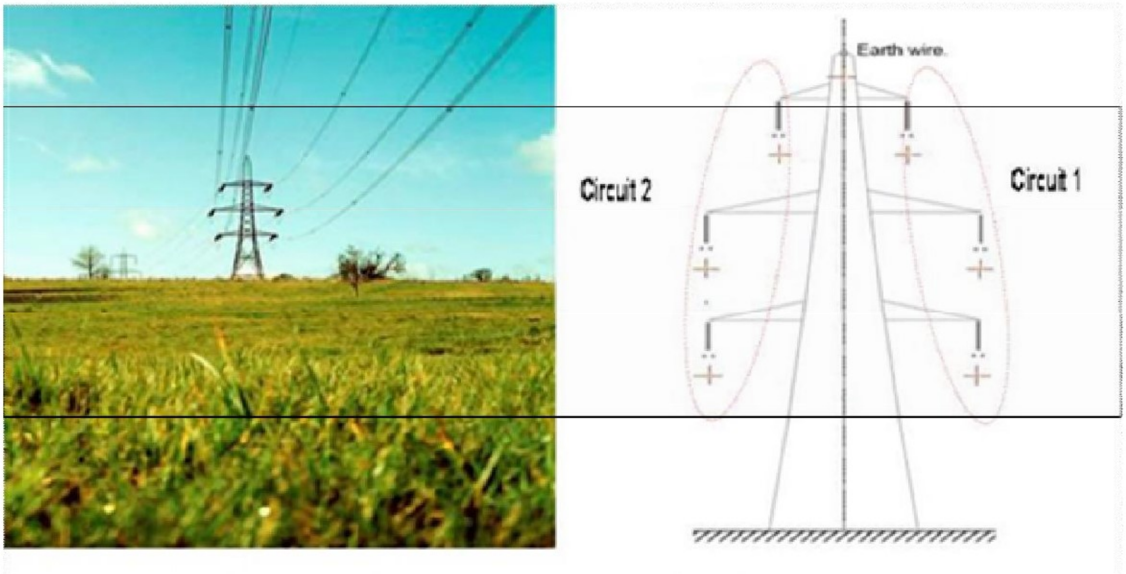
C.2 Overhead lines

C.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.

C.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).

C.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



C.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.

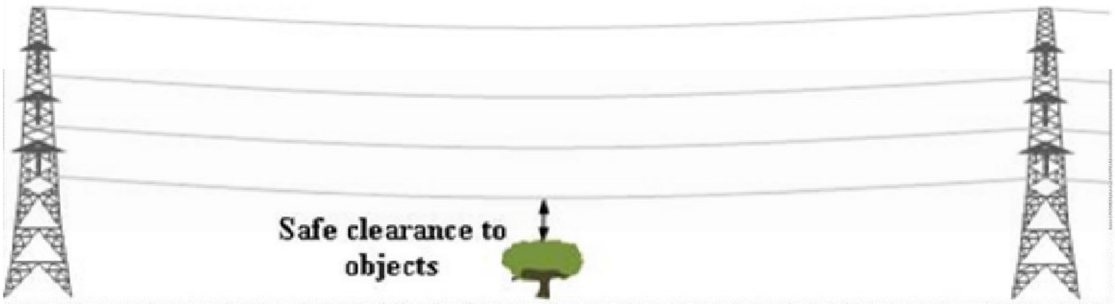
C.2.5 With the conclusion of the Royal Institute of British Architects (RIBA) pylon design competition[8] and other recent work with manufacturers to develop alternative pylon designs, National Grid is now able to consider a broader range of pylon types, including steel lattice and monopole designs. 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.

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

Figure C.2 – The T-pylon

C.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")



C.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.

C.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.

C.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.

C.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.

C.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.

C.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.

C.3 Underground Cables

C.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.

C.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.

C.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

C.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

C.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.

C.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.

C.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.

C.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.

C.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).

C.3.10 The installation of underground cables requires significant civil engineering works. These make the construction times for cables longer than overhead lines.

C.3.11 The construction swathe required for two AC circuits comprising two cables per phase will be between 35-50 m wide.

C.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.

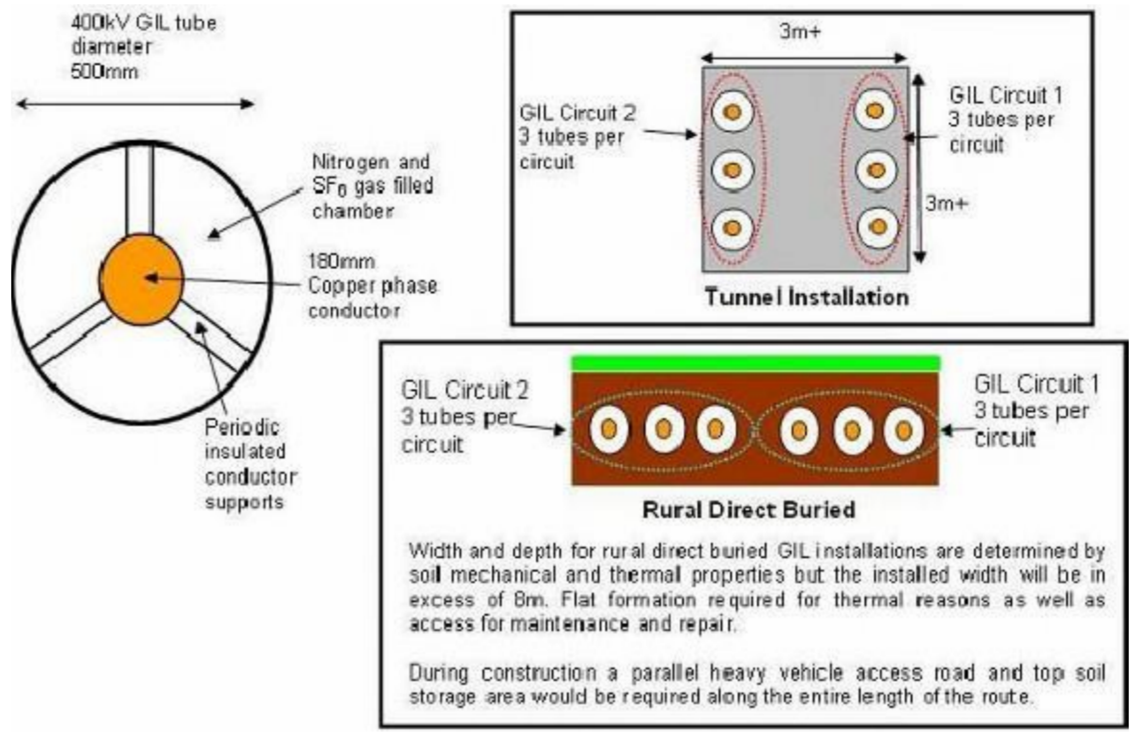
C.3.13 Asset replacement is generally expected at the end of design life. However, National Grid’s asset replacement decisions (that are made at the end of design life) will also take account of actual asset condition and may lead to actual life being longer than the design life.

C.4 Gas Insulated Lines (“GIL”)

C.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.

C.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



C.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.

C.4.4 A major advantage of GIL compared to underground cable is that it does not require reactive compensation.

C.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.

C.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.

C.4.7 There are environmental concerns with GIL as the SF_6[9] 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.

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

C.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.

C.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[10]. 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.

C.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.

C.5 High Voltage Direct Current ("HVDC")

C.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).

C.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.…

C.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.

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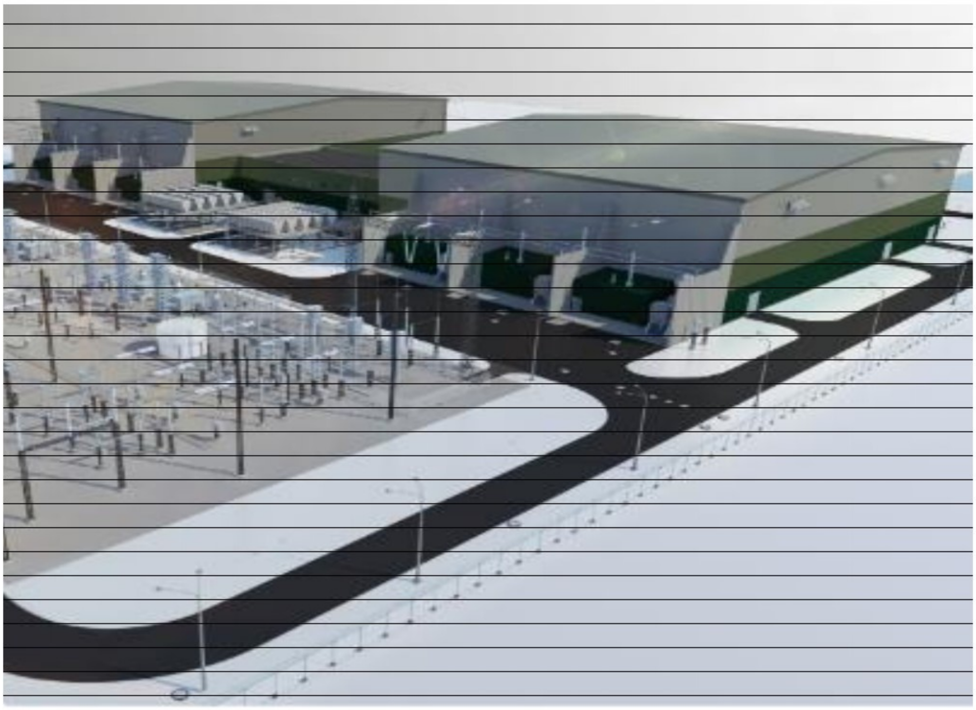
[9] SF_6 is a greenhouse gas with a global warming potential, according to the Intergovernmental Panel on Climate Change, Working Group 1 (Climate Change 2007, Chapter 2.10.2), of 22,800 times that of CO2. www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

[10] 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.

C.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.

C.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.

Figure C.7 – VSC convertor Station



C.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.

C.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

C.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

D.1.1 As part of the economic appraisal of Strategic Options, National Grid makes comparative assessments of the Circuit Lifetime Costs associated with each technology option that is considered to be feasible.

D.1.2 This section provides an overview of the methods that National Grid uses to estimate Circuit 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.

The IET, PB/CCI Report[11] 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.

D.2 Circuit Lifetime Costs for Transmission

D.2.1 For each technology option appraised within a Strategic Option, National Grid estimates total Circuit Lifetime Costs for the new transmission assets. The total Circuit 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

D.3 Capital Cost Estimates

D.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.

D.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.

[11] "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 https://www.theiet.org/media/9376/electricity-transmission-costing-study.pdf.

D.4 AC Technology Capital Cost Estimates

D.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

D.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**			
	275kV AC Technologies	400kV AC Technologies	Overhead Line (OHL)	AC Underground Cable (AC Cable)	Gas Insulated Line (GIL)	Overhead Line (OHL)
	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” tw circuit pylo route (Cost per circuit, of a double circuit pylo 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/kn
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/kn

IET, PB/CCI Report short-form label	Circuit Ratings by Voltage		Technology Configuration			
	275kV AC Technologies	400kV AC Technologies	Overhead Line (OHL)	AC Underground Cable (AC Cable)	Gas Insulated Line (GIL)	Overhead Line (OHL)
	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" tw circuit pylor route (Cost per circuit, of a double circuit pylor route)
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

Notes:

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

D.4.3 Table D.2 provides a summary of the capital costs associated with the key[12] components of transmission circuits for each technology option. Additional equipment is required for technology configurations that include new:

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

D.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.

D.5 AC Underground Cable additional equipment

D.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.

D.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

D.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.

D.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 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.

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

1.2.1 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.

D.5.5 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 60km between substations
Med	Reactive Switching Station every 30km between substations
Hi	Reactive Switching Station every 20km between substations

D.5.6 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.

D.5.7 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	

D.6 Connections between AC 275 kV and 400 kV circuits additional equipment

D.6.1 Equipment that transform voltages between 275kV and 400kV (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.

D.6.2 Table D.6 below shows the capital cost associated with the SGT requirements.

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

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

D.7 High Voltage Direct Current ("HVDC") Capital Cost Estimates

D.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 2GW converter size. Higher ratings are achievable using multiple circuits.

D.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.

D.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 2GW installations

HVDC Converter Type	2 GW Total HVDC Link Converter Costs (Converter Cost at Each End)	2GW 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

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 2GW Link must be capable of operating at ½ its capacity i.e. 1GW 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…)

D.7.4 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).

D.7.5 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.

D.7.6 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 2GW 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 (3190MW)	£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 (6380MW)	£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 (6930MW)	£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])

Notes:

- Costs based on 2GW 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 2GW, so above examples illustrative if technology should become available.

D.8 Indication of Technology end of design life replacement impact

D.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.

D.8.2 National Grid does not take account of replacement costs in the Circuit Lifetime Cost assessment.

D.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.

D.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.

D.9 Net Present Value Cost Estimates

D.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

D.9.2 For both categories, Net Present Value ("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.

D.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.

D.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[13]

"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."

D.9.5 National Grid considered the impact of using the lower Rate of Return (used by UK Government) on Circuit 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.

D.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.

D.10 Annual Operations and Maintenance Cost

D.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.

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[13] 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 400kV 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

D.11 Annual Electrical Losses and Cost

D.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.

D.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.

D.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.

D.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.

D.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	0.4MW per reactor	N/A
Additional losses for 275kV 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

D.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**	**2GW DC Cable Pair Losses**	**2GW 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

D.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.

D.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.

D.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 0.4MW) = 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

D.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.

D.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

D.12 Example Circuit Lifetime Costs and NPV Cost Estimate

D.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 Circuit Lifetime Cost for each technology.

D.12.2 Table D.12 shows an example for a “Med” capacity route 6380 MVA (2 x 3190 MVA) 400 kV, 40km in length over 40 years.

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

Example 400 kV "Med" Capacity over 40km	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
Circuit Lifetime Cost	£273m	£1,236m	£1,306m	£2,203m	£2,617m

Appendix E
Mathematical Principles used for AC Loss Calculation

E.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 textbooks.

E.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.

E.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.

E.2 Example Loss Calculation (1) – 40 km 400 kV “Med” Category Circuits

E.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).

E.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% x 3190 MVA = 1,084.6 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:

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

E.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.

E.2.4 For this “Med” category example, the total resistance for each technology option is calculated (from information in Appendix D, Table D10) as follows:

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

Cable Circuit[14] = 0.0065Ω/km x 40 km = 0.26 Ω

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.

E.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

E.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

E.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

E.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

E.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.

E.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

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

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

$I = 542.3x10^6/(\sqrt{3} \times 275x10^3) = 1{,}138.5$ Amps

E.3.3 For this "Lo" category example, the total resistance for the GIL technology option is calculated (from information in Appendix D, Table D10) as follows:

$0.0086\Omega/km \times 40\ km = 0.344\ \Omega$

E.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

E.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[15] is calculated (from information in Appendix D, Table D10) as 0.2576 Ω.

E.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:

$I_{HV} = 542.3 \times 10^6/(\sqrt{3} \times 400x10^3) = 782.7$ 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.

E.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

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

Appendix F
Glossary of Terms and Acronyms

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 (2012)
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) = 1,000volts
watt (W)		The SI unit of power 1 kilowatt (kW) = 1,000watts 1 megawatt (MW) = 1,000kW 1 gigawatt (GW) = 1,000MW
XLPE		Cross Linked Polyethylene (solid material used to provide electrical insulation)

Appendix G
Appraisal study areas

National Grid plc
National Grid House,
Warwick Technology Park,
Gallows Hill, Warwick.
CV34 6DA United Kingdom

Registered in England and Wales
No. 4031152
nationalgrid.com