Appendices - ESO East Anglia Network Study

March 2024

Appendix 1 – Stakeholder Feedback

This appendix provides an overview of the stakeholder engagement undertaken as part of this study; it contains the following:

1. Overview of our engagement
2. Alternative options submitted by third parties
3. Feedback themes
4. How we have considered the feedback

An overview of our engagement for the East Anglia Study

Our engagement over the course of the three-month study period consisted of four main stages as set out below:

- Five regional roundtables at the beginning of the study to set out the network options under assessment and gain views.
- A written feedback window for those who attended the roundtable to feedback on their design preference or any further information they wanted to provided. This written feedback is summarised in this document.
- Three project update meetings for elected politicians, council officers and wider stakeholders who attended the roundtables to update on project progression.
- Four regional roundtables and a private meeting for elected politicians at the end of the study to present the results of the study.

As this study was not part of any statutory consultation, we engaged with regional elected representatives as well as lead members of relevant special interest groups or regional trade boards at various points throughout to keep stakeholders informed on the study's progress.

The five regional roundtables at the beginning of the study set out the options proposed to assess, pros and cons, as well as the holistic assessment process proposed by us as the Electricity System Operator (ESO) to assess the options.

We communicated with stakeholders through various methods of communication including in-person and online meetings, as well as email. In terms of email, we have responded to over 700 pieces of correspondence on network issues around the East Anglia area.

Alternative options submitted by community representatives

Over the three-month study period, five alternative 'network' options were submitted to us by community representatives for our consideration. These were:

- Proposed Option 1: A predominantly onshore option without the East Anglia Connection Node (EACN).
- Proposed Option 2: Two or more multi-purpose interconnectors (MPIs) with wind farms connecting into them, utilising Bradwell in Essex as well as areas in Kent as an onshore interface point.
- Proposed Option 3: An undergrounded high voltage direct current (HVDC) cable stretching from Norwich in Norfolk to Tilbury in Essex.
- Proposed Option 4: A predominantly offshore option - Utilising Bradwell in Essex as an interface point for HVDC cables.
- Proposed Option 5: An offshore ring main, connecting all wind farms around the coast of the region, utilising brownfield sites for onshore interface points, such as Bradwell and areas in Kent.

Preliminary assessment process

To determine whether options submitted to us should be taken forward to the next stage of holistic assessment (holistic assessment is set out in more detail in the Methodology appendix below), we have screened these options against the below criteria as outlined within the table below.

	Proposal 1	Proposal 2	Proposal 3	Proposal 4	Proposal 5
Description	**Onshore option without EACN**	**Two or more MPIs**	**Underground onshore HVDC**	**Predominantly offshore option - Utilising Bradwell as a landing point**	**An offshore ring main**
Criteria 1: Is this proposal in scope of the study's Terms of Reference[1]?	Yes	No	Yes	Yes - if Bradwell is hosting transmission infrastructure, no if it is hosting generation infrastructure	No
Criteria 2: Would the proposal require a change in connection location for projects not exploring voluntary coordination through the OCSS?	Within the sensitivity range of the study	Yes	No	No – if only wider network HVDC landing points were considered	Yes
Criteria 3: Is the proposal technically feasible in the timescales the capacity is needed?	Yes	Yes - if regulatory regime is in place	Yes	Yes	No
Progression to next stage of assessment	**Yes**	**No**	**Yes**	**Yes – if the proposal is only moving network transmission infrastructure to Bradwell**	**No**

Table 1: Screening of options submitted to the ESO for consideration

[1] East Anglia Study – Terms of Reference - https://www.nationalgrideso.com/document/283571/download

Proposed Option 1:

Option Description	The ESO understands this option to be variation of the onshore option currently already under assessment in our study, but without the proposed EACN.
Decision	The ESO has taken this option to the next stage of assessment. A full holistic assessment of this option will be presented within the report.
Criteria 1	This option meets the study's Terms of Reference, published in March 2023.
Criteria 2	The proposed option does not propose moving customer connection locations that are not otherwise in scope or within the sensitivity range of this study and is focusing on alternative network transmission.
Criteria 3	This option is technically feasible and would meet the system's need in the required timescales. It utilises existing technology which are as follows: • HVDC undersea cable technology • Associated onshore HVDC converter stations • Associated onshore Alternating Current (AC) substation • 400 kV AC onshore overheard circuit

Proposed Option 2:

Option Description	The ESO understands this option to be the use of two or multipurpose interconnectors (offshore hybrid assets), where an interconnector between Great Britain and another country is also used to connect multiple wind farms to Great Britain's system. These multi-purpose interconnectors would connect to a brownfield site in Great Britain. A number of such arrangements would be needed to solve the need.
Decision	The ESO has not taken this option to the next stage of assessment (a full holistic assessment).
Criteria 1	This option does not meet the study's Terms of Reference, published in March 2023. The early opportunities workstream and its subsequent output, the Offshore Coordinated Support Scheme (OCSS), was a government-facilitated incentivisation scheme for developers within the region. The outcome of the first phase was announced on 5 December 2023, which resulted in two offshore wind farms exploring voluntary coordinating with an offshore transmission link between Suffolk and Kent. As stated in our Terms of Reference, we are reviewing the outputs of the early opportunities workstream. A multi-purpose interconnector was not taken forward by developers involved with the early opportunities workstream and subsequent OCSS.
Criteria 2	This option involves moving the connection locations of customers outside the scope of OCSS, including offshore wind farms that did not take part in the early opportunities workstream. As with any contract, commitments are given and contractual certainty is important for the contracting parties, especially those involving significant investment. As the ESO we have no powers to unilaterally force other developers within the region to be a part of the OCSS. The ESO is contractually obliged to honour existing connection agreements and could be subject to legal challenge if we were to look to unilaterally alter or disregard contractual agreements.

Criteria 3	This option is technically feasible. It utilises existing technology which are as follows: • HVDC undersea cable technology. • Associated onshore HVDC converter stations • Associated onshore AC substations • 400 kV AC onshore overheard circuit There is a risk however, that this option may not meet the system need in the required timescales due to the factors set out below. There are currently three interconnectors with connection planned in the region; the ESO understands that while some of these are exploring whether to become multi-purpose interconnectors[2], they are not doing so with Great Britain-based offshore wind. At present the regulatory environment for the Offshore Hybrid assets is not fully developed. In February 2024, the Office of Gas and Electricity Markets (Ofgem) published a framework which included a high-level regulatory regime only for the projects participating in Ofgem's pilot scheme. Explicitly, Ofgem note that future projects may have a different regulatory regime. An interconnector and wind farm may choose to become part of the pilot scheme[3], but the ESO cannot force them to coordinate, while MPIs were included in the initial batch of options being looked at through the early opportunities workstream, the outcome, decided between the relevant developers, was not a multi-purpose interconnector. Due to existing size and capacity of HVDC cable technology, each proposed multi-purpose interconnector would be limited to less than 2 GW. Meaning multiple cables and converter stations could be required. We are also limited by needing to ensure that the system is secure, so that a fault on the transmission system does not cause too great a loss of generation. The Security and Quality of Supply Standard (SQSS) infeed loss[4] for planning and operating an offshore transmission system governs the maximum allowable disconnection of generation allowed. For offshore generation the infeed loss will be increased from 1320 MW to 1800 MW for normal infeed loss risks. This increased infeed loss allows for a larger, more efficient design without negatively impacting customers. Therefore, each 1.8 GW of connection, or connections, would need to be able to be separated from the other element so any loss could be managed. It is also worth noting that this option would not remove the need for onshore electricity transmission infrastructure. While it may move the infrastructure to other areas within the region or further afield, ultimately similar levels on onshore infrastructure will be required to move the electricity to homes and businesses across Great Britain.

Proposed Option 3:

Option Description	The ESO understands this option to be an undergrounded route from Norwich to ultimately Tilbury using HVDC underground cable technology.
Decision	The ESO has taken this option to the next stage of assessment. A full holistic assessment of this option will be presented within the report.
Criteria 1	This option meets the study's Terms of Reference, published in March 2023.

[2] About Nautilus | National Grid Group
[3] Decision on the Regulatory Framework for the Non-Standard Interconnectors of the Offshore Hybrid Asset pilot scheme | Ofgem
[4] GSR013: Review of Offshore Infeed Loss | ESO (nationalgrideso.com)

Criteria 2	The proposed option does not propose moving customer connection locations that are not otherwise in scope of this study and is focusing on alternative network transmission.
Criteria 3	This option is technically feasible and from preliminary assessment could meet the system need in the required timescales. It utilises existing technology which are as follows: • HVDC underground cable technology • Associated onshore HVDC converter stations • Associated onshore AC substations

Proposed Option 4:

Option Description	The ESO has designed this option to utilise Bradwell as a landing point for an HVDC subsea cable moving power within and out of the region, replacing an existing landing point such as Friston.
Decision	The ESO has taken this option to the next stage of assessment. A full holistic assessment of this option will be presented within the report.
Criteria 1	This option meets the study's Terms of Reference, published in March 2023.
Criteria 2	The proposed option does not propose moving customer connection locations that are not otherwise in scope of this study and is focusing on alternative network transmission.
Criteria 3	This option is technically feasible and from preliminary assessment could meet the system need in the required timescales. It utilises existing technology which are as follows: • HVDC underground cable technology • Associated onshore HVDC converter stations • Associated onshore AC substations • 400 kV AC onshore overheard circuit

Proposed Option 5:

Option Description	The ESO understands this option to be the development of a significant offshore network, sometimes referred to an offshore spine, ring main, backbone, interconnected energy islands etc., with a number of connection points back to the onshore network at brownfield sites.
Decision	After a preliminary assessment the ESO has not taken this option to the next stage of assessment (a full holistic assessment).
Criteria 1	The early opportunities workstream and its subsequent output, the OCSS, was a government-facilitated incentivisation scheme for developers within the region. The outcome of the first phase was announced on 5 December 2023, which resulted in two offshore wind farms exploring voluntary coordinating with an offshore transmission link between Suffolk and Kent. As stated in our Terms of Reference, we are reviewing the outputs of the early opportunities workstream.

Criteria 2	This option involves moving the connection locations of customers outside the scope of OCSS. As with any contract, commitments are given and contractual certainty is important for the contracting parties, especially those involving significant investment. As the ESO we have no powers to unilaterally force other developers within the region to be a part of the OCSS. The ESO is contractually obliged to honour existing connection agreements and could be subject to legal challenge if we were to look to unilaterally alter or disregard contractual agreements.
Criteria 3	This network configuration would potentially require the use of the following technology, some of which is not commercially available at the scale required: • Hybrid offshore assets • HVDC undersea cable technology • HVDC switch gear and circuit breakers • Associated onshore HVDC converter stations • 400 kV Overhead Circuits AC The ESO does not believe this option to be technically viable in the timescales required. A technology maturity review[5] was conducted as part of the recent Offshore Coordination Project for the ESO. Information from the review together with latest evidence available to us as well as our own engineering view have informed our technical view of this option. There is a significant amount of wind resource planned off the coast of East Anglia, more than 12 GW worth of offshore wind farms under planning or construction with connection dates before 2030. This wind is part of the Government's ambition to meet 50 GW of offshore wind nationally by 2030. This option would require the collection of significant quantity of wind resources offshore to a number of offshore platforms (each of multiple GWs of wind), interlinking of these platforms, and then linking back to shore. This option is a fundamental change in approach by requiring coordination for advanced stage projects, the ESO believes it would not be technically feasible within the timescales required. HVDC network technology is well suited for long distance transmission and offshore use but are currently limited to around 2 GW circuit capacity for offshore use. Therefore, multiple HVDC circuits with multiple HVDC converter stations (typically the size of a B&Q warehouse) back onshore would be required for this proposed option. HVDC circuit breakers are switches which allow network components to be separated safely should an electrical fault occur in an HVDC network. These would enable more complex and interconnected configurations to be used in situations where HVDC transmission is required, which is often the case in offshore networks due to the distances involved and the requirement for cabling. Their High Voltage Alternating Current (HVAC) equivalent is well established technology which has allowed complex and interconnected HVAC networks to be developed into the form used in Great Britain today.

[5] download (nationalgrideso.com)

HVDC circuit breakers are currently in development, but none are currently commercially available at the size and voltages needed, with no examples currently installed in the UK or Europe.

Overall, to deliver this level of infrastructure offshore would be extremely challenging and would almost certainly be undeliverable in or near to the early 2030s – this would delay the connection of wind that is due to connect in by 2030 to reach the UK Government's offshore wind ambition.

The option is more aligned with some of the future European Network of Transmission System Operators – Electricity (ENTSO-E)[6][7] views for further offshore development, where they state the emergence of HVDC circuit breaker technology into the mid-2030s at the earliest but with significant uncertainty. The ENTSO-E Offshore Network Development Plans models *"optimistic conditions with: lowest costs, offshore converter stations being already prepared to host potential DC-circuit-breakers and the early availability of commercially attractive DC circuit breakers – at least from 2040 onwards".* It also includes scenarios without the breakers ever being available, reflecting the uncertainty on emerging technologies.

We are also limited by needing to ensure that our system is secure, so that a fault on the transmission system does not cause too great a loss of generation. The SQSS infeed loss[8] for planning and operating an offshore transmission system governs the maximum allowable disconnection of generation allowed.

For offshore generation the infeed loss will be increased from 1320 MW to 1800 MW for normal infeed loss risks. This increased infeed loss allows for a larger, more efficient design without negatively impacting customers. Therefore, each 1.8 GW of connection, or connections, would need to be able to be separated from the other element so any loss could be managed.

Other countries are looking at the energy island concept – but the initial plans are for much smaller-scale island and coordination similar to what is proposed around the UK, with coordination of cable routes and some 'pooling' of wind farms offshore. For example, initially:

- Vindo Island in Denmark, by 2033 plans to coordinate 3 GW of offshore wind radially back to a connection onshore.
- Princess Elizabeth Island in Belgium is similarly an initial plan to coordinate 3.5 GW of offshore wind by 2030, radially back to the connection onshore, via six AC export cables and one HVDC export cable.

We look forward to when the technology required, HVDC circuit breakers, are available at the scale and voltages required.

It is also worth noting that this option would not remove the need for onshore electricity transmission infrastructure. While it may move the infrastructure to other areas within the region or further afield, ultimately similar levels on onshore infrastructure will be required to move the electricity to homes and businesses across Great Britain.

[6] HVDC Circuit Breakers - ENTSO-E (entsoe.eu)

[7] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/ONDP2024-pan-EU-summary.pdf

[8] GSR013: Review of Offshore Infeed Loss | ESO (nationalgrideso.com)

Feedback sentiment

Assessing community sentiment

Reflecting the high-level nature of our methodology, we wanted to be able to show the sentiment of those we engaged with (primarily elected representatives and special interest groups) during our study in order to aid future potential development of these options, should they be taken forward by the Transmission Owner.

Consequently, all options under holistic assessment where also BRAG rated for community sentiment. The definition of BRAG ratings are as follows:

Black –The option was unanimously not supported.

Red – The majority of stakeholders engaged did not support the option, with a minority of stakeholders supporting or seeing benefit in components of the option.

Amber – The option was supported by majority of stakeholders; however, a concentrated minority did not support the option.

Green – The option was unanimously supported across stakeholders engaged.

Option Number	Option description	Community sentiment	Commentary
1	Predominately offshore option – variation without East Anglia Connection Node (EACN)	Amber	This option negates the need for new overhead lines – removing visual impact; however, it has significant concentrated impact at proposed coastal nodes. Some community representatives in Norfolk and Friston in particular, strongly opposed this option due to the concentrated impact at these proposed nodes.
2	Predominately offshore option – variation with EACN	Red	This option involves a short OHL/UG onshore infrastructure through an Area of Outstanding Natural Beauty.
3	Onshore option	Red	This option has new overhead lines – with visual impact spanning across three regions. Significant concentrated impact at proposed substations.
4	Alternative Onshore option – variation without Bramford EACN	Red	This option has new overhead lines – with visual impact spanning across three regions. Significant concentrated impact at proposed substations.
5	Alternative Onshore option – variation without EACN	Red	This option has new overhead lines – with visual impact spanning across three regions. Significant concentrated impact at proposed substations.
6	Hybrid onshore and offshore option	Red	This option has a mixture of new overhead lines and subsea cables with visual impact spanning across three regions. Significant concentrated impact at proposed substations.
7	Hybrid onshore and offshore option – variation without EACN	Red	This option has a mixture of new overhead lines and subsea cables with visual impact spanning across three regions. Significant concentrated impact at proposed substations.

Option Number	Option description	Community sentiment	Commentary
8	Onshore HVDC Option	Amber	Onshore routes but undergrounded are view more favourably. Still significant impact at Friston, Norwich and Tilbury for converter stations and potentially at EACN (depending on the exact nature of any design).
9	Predominantly offshore option – utilising Bradwell as a landing point	Amber	This option involves an uprating of an existing overhead line which could have a visual impact; however, it has significant concentrated impact at proposed coastal nodes.

Table 2: Table showing community sentiment of assessed options.

In addition to the four assessment criteria (set out below in the Methodology Appendix) used to assess options as part of the holistic assessment, we assessed the community sentiment of all options. We are however unable to quantify this assessment and represent the views of the whole community. The results of this assessment are set out in the table below.

Wider feedback themes

There were several key themes that came through from our stakeholder engagement, which we have summarised below.

Study's scope

Some of the stakeholders engaged with felt the study's scope were not broad enough, and that all offshore generation in development off the coast of the region should have been in scope of the study.

Answer and actions undertaken: We published the study's Terms of Reference in March 2023, it stated that it would examine the regions infrastructure requirements following the OCSS decision.

We understand that some stakeholders are disappointed in the OCSS outcome and had hoped that other configurations were brought forward to the next stage. We also recognise that other stakeholders were pleased with its outcome.

As the ESO, we have no powers to compel developers to be a part of OCSS, nor change the outcome of the OCSS or unilaterally move a customer's connection location. Where possible, we have tried to accommodate alternative network configuration option requests and transparently explain why it has not been possible to accommodate others.

Economic assessment and wider cost considerations

Some stakeholders raised questions pertaining to our economic assessment and whether wider socio-economic costs were considered, specifically if we adopted the Treasury Green Book principles in our analysis.

Answer and actions undertaken: The Green Book provides standard guidance for evaluating benefits and outcomes of projects. Transmission Owners follow a robust assessment process and national guidance, primarily the National Policy Statement (NPS) for Electricity Networks Infrastructure.

Transmission Owners' proposals are subject to independent high-level assessment of their ability to meet electricity network needs by the ESO. Our holistic assessment was signed off by the UK Government for use under the Offshore Transmission Network Review (OTNR).

Ofgem expects Transmission Owners to reference the Green Book in their submissions, particularly when providing evidence on the forecast benefit of their projects, but its application is not enforced. There is no requirement in the Planning Act 2008 for a Green Book assessment to be included in Development Consent Order applications.

We, the ESO, also do not currently adopt the Treasury Green Book principles in full for our high-level electricity network planning assessments as our methodology is high level, it therefore does not include assessing local economic factors such as impact on tourism or impact on regional gross domestic profit (GDP).

For continuity and equity with all our usual electricity network planning processes we have conducted this assessment using the same criteria as utilised in the Holistic Network Design which includes cost to consumers; deliverability and operability; impact on the environment and impact on local communities. The Holistic Network Design (HND) methodology was agreed with the UK Government through the OTNR process.

Network technology – advancements in onshore network infrastructure

Some stakeholders raised questions as to whether the Transmission Owner was using the latest technology and designs when it came to onshore network infrastructure such as pylons and underground cables.

Answer and action taken: The options considered already use some of the suggestions. High Temperature Low Sag conductor, including composite core, is already within the set of conductors considered. There are advantages and disadvantages to the different conductor types such as noise, ability to join, sag profiles and wind loading. The selection can only be made following detailed surveys. Latest technology can be considered in detailed design but needs to have suitable maturity to ensure successful delivery and reliable operation.

Specific installation techniques depend on many factors such as the ground hardness, access, and thermal conductivity. Selection is only possible following detailed survey and planning which is beyond the scope of this study. This study has used typical parameters based on experience and knowledge of expected methods.

The use of high voltage underground cable over long distances will be limited by the cable charging currents and thermal dissipation. See the DNV report appendix. HVDC overcomes some of the underground AC cable limitations but requires HVDC converters at each end and each circuit currently cannot carry as mush power as the AC circuits. Until HVDC circuit breakers become readily available, the large-scale interconnection of HVDC circuits is not feasible.

Design options with greater onshore footprint

It was suggested that the onshore option (Option 3) and alternative onshore option (Options 4 and 5) have a greater onshore footprint and do more damage than the counterfactual starting point. Stakeholders also raised concerns that all options under initial assessment had a greater infrastructure footprint proposed around Friston.

Answer and actions undertaken: We have studied a range of options to consider their impact across four objectives and that is standard practice across high-level network planning. It is possible to mitigate community impact onshore but more challenging to mitigate the environmental impact offshore due to the large Special Protected Areas (SPAs) and Special Areas of Conservation (SACs) offshore. It is easier to avoid the onshore constraints areas as they are smaller in size.

The need for an additional line from Friston is a consequence of the cumulative total of generation connected at or near Friston under the OCSS, which brings North Falls and Five Estuaries more electrically closer. The additional circuit is required to ensure that the generation can continue to export even if there is a fault with one of the network routes, as required under the planning rules for the transmission network.

After receiving stakeholder feedback on the cumulative impact of those communities living at Friston, we tried to design an alternative option, uses Bradwell as a landing point of HVDC network (see option 9).

Grid connectivity

Some elected representatives in Norfolk raised the ongoing challenge of grid connectivity and the need for host communities to be able to utilise and take advantage of the transmission electricity they may be hosting.

Answer and actions undertaken: We share in the frustration in the length of time it takes to connect into the transmission and distribution electricity grid. We are working closely with the UK Government and the regulator to bring forward reforms to the grid connection process to speed up this process.

Building wider electricity transmission capability, such as the options under assessment in this study will reinforce the electricity grid, leading to more points at which customers can connect into the grid. The assessment does also look at an economic sensitivity, whereby the region increases its electricity demand by 2 GW and what that could do the electricity transmission network needs of the region.

East Anglia Connection Node

During our engagement with representatives from Essex, the proposed East Anglia Connection Node (EACN) was raised at length. We received a detailed evidence pack regarding its proposed location as well as other written responses referencing the proposed connection node.

Answer and actions taken: Currently North Falls and Five Estuaries offshore wind farms and Tarchon interconnector drive the need for the East Anglia Connection Node on the Tendring Peninsula. Under OCSS, North Falls and Five Estuaries would connect elsewhere, and therefore, only Tarchon would be left at the Node.

Therefore, as part of our study, we are considering the impact if Tarchon were to be located elsewhere. For the avoidance of doubt, we cannot compel Tarchon to connect elsewhere, but as part of the study we are showing the impact on the wider network if they did connect elsewhere.

In response to stakeholder feedback, we have adopted an additional option, now in total four options that do not have the proposed node within it, meaning the proposed circuit option could be routed another way. These options are options 1, 5, 7 and 9.

This study is a high-level assessment, proposed substation locations are a matter for the relevant Transmission Owner and therefore the location of the EACN substation is not assessed within this study.

Conclusion and next steps

Thank you to those that have provided feedback in writing and at our roundtables. Where possible your feedback has been considered as we have assessed our network configuration options.

If you have questions or further feedback, please get in touch with us via eastangliastudy@nationalgrideso.com

Appendix 2 - Additional Economic Analysis & Sensitivities

Capital Cost

The capital cost of the options varies from a minimum of £2.3 billion for Option 5 - Alternative onshore option – variation without East Anglia Connection Node (EACN), to £6.3 billion for Option 2 – Predominately offshore option (with EACN). Option 5 comprises the smallest number of circuits and does not build EACN. In comparison Option 2 includes EACN, an onshore line from Bramford to EACN and a large amount of comparatively more expensive HVDC subsea cable.

Option Number	Option description	Total capital cost
1	Predominately offshore option (without East Anglia Connection Node(EACN))	£6,228m
2	Predominately offshore option (with EACN)	£6,360m
3	Onshore option (closest to status quo)	£2,585m
4	Onshore option – variation with EACN	£2,453m
5	Onshore option – variation without EACN	£2,325m
6	Hybrid onshore and offshore option (with EACN)	£4,590m
7	Hybrid onshore and offshore option (without EACN)	£4,462m
8	Onshore HVDC option	£4,871m
9	Predominantly offshore option – utilising Bradwell as a landing point	£5,173m

Table 1: Table showing capital costs of the assessed options

In the following table, the breakdown of the costs (as a percentage of each option total) for the components making up that option are shown.

Important caveat on costs. The costs included within this Study are for indicative purposes only. They provide a high-level indication of the costs associated with delivering the network infrastructure, based on principles and assumptions of the level of functionality required. This is particularly the case for the community options (Option 8 and 9) which were late additions to development of this Study. It is important to advise, these costs have not been derived from any detailed assessments, and we understand from the National Grid Electricity Transmission that these costs are likely to underestimate the full deliverable costs of schemes, especially those involving HVDC converter stations - given the complexity of the global market. If any scheme was to be taken forward, from the current high-level design included within the Study into more detailed design, the costs would all be subject to detailed revision.

Option Number	Circuit	Technology	Percentage of option cost
1	Norwich-Grain	2 * 2 GW HVDC link	40%
	Friston-Sellindge	2 GW subsea link	37%
	Sea Link	2 GW subsea link	23%
		TOTAL	**£6,228m**
2	Norwich-Grain	2 * 2 GW HVDC link	39%

Option Number	Circuit	Technology	Percentage of option cost
	Friston-Sellindge	2 GW subsea link	36%
	Bramford-EACN	Double cct onshore OHL	2%
	Sea Link	2 GW subsea link	22%
		TOTAL	**£6,360m**
3	Norwich-Bramford	Double cct onshore OHL	14%
	Bramford-EACN	Double cct onshore OHL	5%
	EACN-Tilbury	Double cct onshore OHL	16%
	Friston - EACN	Double cct onshore OHL	10%
	Sea Link	2 GW subsea link	55%
		TOTAL	**£2,585m**
4	Norwich-Bramford	Double cct onshore OHL	14%
	EACN-Tilbury	Double cct onshore OHL	17%
	Friston - EACN	Double cct onshore OHL	11%
	Sea Link	2 GW subsea link	58%
		TOTAL	**£2,453m**
5	Norwich-Bramford	Double cct onshore OHL	15%
	Friston -Tilbury	Double cct onshore OHL	24%
	Sea Link	2 GW subsea link	61%
		TOTAL	**£2,325m**
6	Norwich-Grain	2 * 2 GW HVDC link	54%
	EACN-Tilbury	Double cct onshore OHL	9%
	Friston - EACN	Double cct onshore OHL	6%
	Sea Link	2GW subsea link	31%
		TOTAL	**£4,590m**
7	Norwich-Grain	2 * 2 GW HVDC link	56%
	Friston -Tilbury	Double cct onshore OHL	12%
	Sea Link	2 GW subsea link	32%
		TOTAL	**£4,462m**
8	Norwich-Tilbury	2 GW onshore, underground HVDC	24%
	Friston - Tilbury	2 GW onshore, underground HVDC	21%
	Norwich - EACN	2 GW onshore, underground HVDC	15%
	EACN - Tilbury	2 GW onshore, underground HVDC	11%
	Sea Link	2 GW subsea link	29%

Option Number	Circuit	Technology	Percentage of option cost
		TOTAL	**£4,871m**
9	Norwich-Grain	2 * 2 GW HVDC link	48%
	Bradwell - Sellindge	2 GW subsea link	21%
	Bradwell - Rayleigh	Double cct onshore OHL	3%
	Sea Link	2 GW subsea link	27%
		TOTAL	**£5,173m**

Table 2: Table showing capital cost of the different components of options

Cost benchmarking

We have compared the cost of the components of the options against projects in Great Britain and Europe. To do this we have used two datasets – the ENTSO-E (European Network of Transmission System Operators for Electricity)[9] Ten Year Network Development[10] 2022 (the most recent dataset) for HVDC projects, and the Great Britain Transitional Centralised Strategic Network Plan 2 (TCSNP2) for onshore projects.

The cost of each transmission project is unique based on specifics of the project such as capacity, technology, geography and national factors such as cost of labour, planning etc. However, to benchmark the costs of the components within the options in this study, we have calculated a measure of £/MWkm for each component. The £/MWkm measure is used as it represents the cost of expanding the transmission network, as it represents the cost of moving one megawatt, one kilometre, and forms the basis for how generators and suppliers pay transmission charges for using the network. This allows projects of different lengths and capacities to be compared.

All prices are converted into 2023/24 price base, and into pounds at the exchange rate of 0.85 GBP to 1 EUR where appropriate.

HVDC circuits

We have compared the cost of the offshore HVDC schemes in this assessment with the dataset from the ENTSO-E[11] Ten Year Network Development[12] 2022 (TYDNP22) (the most recent dataset). This dataset is a pan-European set of significant transmission infrastructure projects. It included 141 transmission projects, of which 66 were HVDC schemes.

The following chart shows the distribution of the cost of all 66 HVDC schemes in the TYDNP22. The cheapest scheme at 741 £/ MWkm is a long distance and high capacity HVDC scheme across the Mediterranean from Greece to Egypt. The most expensive is over 9,500 £/MWkm for a New HVDC tri-terminal link between mainland Italy, Corsica and Sardinia. This scheme has a relatively low capacity for an HVDC link, and over a short-distance such is the nature of the geography.

[9] ENTSO-E is the European Network of Transmission System Operators for Electricity, a pan-European body (of which the UK is not a part), whose members are the European Transmission System Operators who are responsible for the bulk transmission of electric power on the main high voltage electric networks.
[10] https://tyndp.entsoe.eu/
[11] ENTSO-E is the European Network of Transmission System Operators for Electricity, a pan-European body (of which the UK is not a part), whose members are the European Transmission System Operators who are responsible for the bulk transmission of electric power on the main high voltage electric networks.
[12] https://tyndp.entsoe.eu/

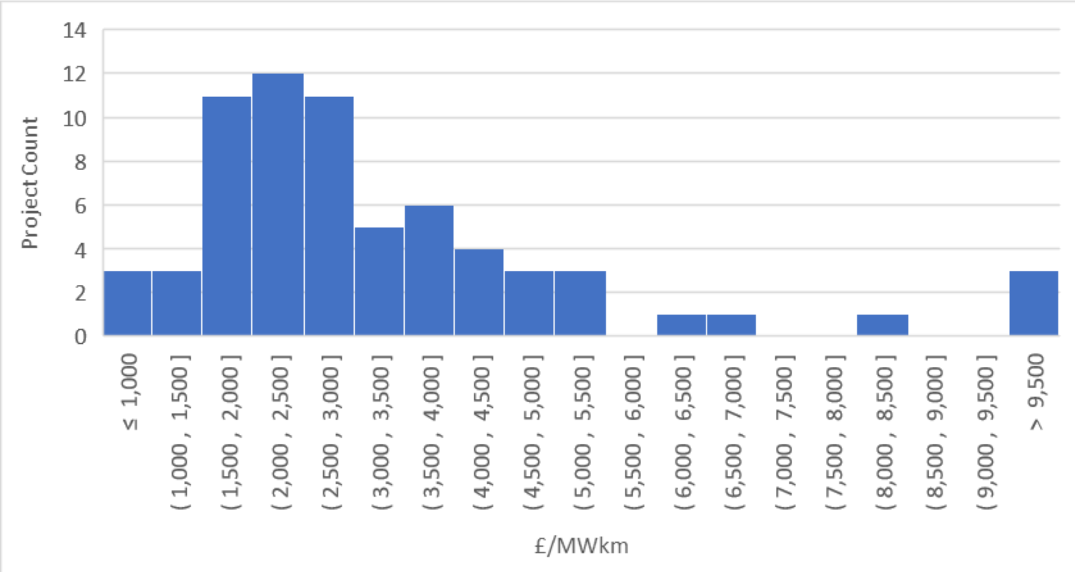

Figure 1:Histogram of £/MWkm comparative cost of the TYNDP projects

There are nine HVDC elements in the East Anglian options. Between there comparative unit cost ranges from minimum of £3,115/MWkm to £4,900/MWkm. The data has a mean of £3,762/MWkm and a median of £3,619/MWkm

The HVDC elements in the East Anglian options fits within the ENTSO-E dataset, and would range from the 61% percentile of the dataset to the 89% of the dataset. This does means that the GB schemes are 'above average' in cost compared to the European average. However, the

cost of HVDC projects is driven by two key factors – the cost of converters (which are always required), and the cost of the cable which is dependent on length. The projects in East Anglia, with a median length of 150km are short in comparison to the European dataset, where the median length amongst the projects is 300 km. This means that the converter stations play a larger role in the unit cost of shorter HVDC links.

Eastern HVDC links from Scotland to England

Two HVDC are being constructed from Scotland to England. EGL1 from Torness to Hawthorn Pit (~200km), and EGL2 from Peterhead to Drax subsea HVDC (~500km). The Ofgem final determination[13] on funding these projects put the costs at £3.4 billion (2019/20 prices). This is equivalent to around £4.1 billion in today's prices adjusted for inflation.

Circuit	Cost (£m)	Capacity (GW)	Length (km)	£/MWkm
Torness to Hawthorn Pit	~£1600m	2	200km	4000
Peterhead to Drax	~£2500m	2	500km	2500

Table 4: Unit cost of the two planned England Scotland Green Link HVDC circuits on the East Coast

The longer Eastern Link from Peterhead to Drax is comparatively per unit cheaper, due to the longer distance and the high cost of converter stations. Overall, the costs of the HVDC links in East Anglia are comparable to the costs for the two Scottish link.

A press release[14] in December 2023, from the joint venture delivering the project put the total cost of the Torness to Hawthorn Pit link at £2.5 billion. This would make the unit cost £6,250 /MWkm.

[13] https://www.ofgem.gov.uk/sites/default/files/2022-07/Eastern%20HVDC%20-%20Decision%20on%20the%20project%27s%20Final%20Needs%20Case.pdf

[14] https://www.easterngreenlink1.co.uk/news/eastern-green-link-1-ltd-awards

Onshore AC circuits

In March 2024, we will publish the Transitional Centralised Strategic Network Plan 2 (TCSNP2) which will outline Great Britain's electricity network needs from 2030s and beyond, several new onshore circuits are being proposed in that design across Great Britain from various Transmission Owners.

We have cross checked the costs within the TCSNP2 with those within this independent assessment. In this assessment, there are six different onshore AC lines. There units costs have a minimum of £704/MWkm, and a maximum of £904/MWkm. The mean is £811/MWkm and the median £815/MWkm.

In comparison the

data from TCSNP2 schemes (which includes projects from across Great Britain) has a minimum of 600 £/MWkm, and a maximum of 2,600 £/MWkm. The average is 1,400 £/MWkm.

All the onshore components within this assessment have a £/MWkm lower than the average of TCSNP2. This shows that costs for the onshore elements in East Anglia are very comparable to costs elsewhere in Great Britain, and the below average cost potentially reflect less complex geography in East Anglia compared to somewhere like the Scottish Highlands, or the North of England.

Constraint costs

The following tables shows the remaining constraint costs over the over the 40-year lifespan of the reinforcements per each option. When designing the transmission network, it is acceptable to leave a level of constraint in the network, which occurs at only limited times and costs. These residual constraints are a sign of a network that has not been 'over built'.

The costs are shown per FES Scenario, with costs normalised so the option with the lowest constraint cost has zero additional constraint cost. A higher constraint cost shows an option incurs more constraints over its lifetime.

Constraint costs relative to best option per scenario	FES Scenario			
	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£1,642m	£3,177m	£1,378m	£1,041m
Option 2	£2,148m	£4,234m	£1,787m	£1,584m
Option 3	£0,569m	£1,832m	£0	£0
Option 4	£2,856m	£6,136m	£1,020m	£2,106m
Option 5	£11,263m	£16,275m	£11,593m	£8,633m
Option 5b	£2,346m	£5,324m	£1,865m	£1,361m
Option 6	£0,526m	£1,852m	£1,093m	£0,708m
Option 7	£0,759m	£1,644m	£1,232m	£0,404m
Option 8	£0	£0	£0,909m	£0,216m
Option 9	£7,784m	£12,083m	£3,004m	£7,095m

Table 6: Constraint costs associated with each option, under the FES scenarios

The difference in costs per scenario is a function of the different regional and national generation mixes that happen across time in each of the scenarios. In two of the net-zero scenarios (LtW and CT), the onshore HVDC (option 8) performs most effectively at reducing constraint costs. In two of the net-zero scenarios (ST and FS), the onshore option (option 3) performs most effectively. The comparatively expensive cost of Option 5 is due to the lower network capacity that this option provides and moving one of the interconnectors outside the region to Grain. The analysis in this table does not take into account the difference in capital cost.

Lifetime cost assessment

The lifetime cost assessment compares the present value (PV) of the various reinforcement option CAPEX with the PV of forecasted constraint cost / savings. For each reinforcement option, the PV of both the annual constraint savings and the associated capital cost is calculated; their difference gives the option's net present value (NPV).

Over the lifetime of an option, when considering which option is overall the most economic, there are two costs to the consumer to consider: the sum of the capital cost and any additional constraints an option might cause. Therefore, we need to sum the capital cost of each option with the constraint cost. The costs have been re-baselined to show zero for the lowest total cost option.

Total additional cost compared to the best option, per scenario	FES Scenario			
	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£4,211m	£4,785m	£4,517m	£4,180m
Option 2	£4,832m	£5,956m	£5,040m	£4,837m
Option 3	£0m	£301m	£0m	£0m
Option 4	£2,037m	£4,356m	£771m	£1,857m
Option 5	£10,340m	£14,389m	£11,239m	£8,278m
Option 5b	£1,422m	£3,439m	£1,510m	£1,006m
Option 6	£1,672m	£2,037m	£2,809m	£2,423m
Option 7	£1,794m	£1,718m	£2,836m	£2,009m
Option 8	£962m	£0m	£2,439m	£1,747m
Option 9	£8,981m	£12,318m	£4,771m	£8,862m

Table 7: Cost Benefit Analysis of each option, per FES scenario

In three FES scenarios (LW, ST and FS) Option 3 - Onshore option, has the lowest overall cost to consumer. In one scenario (CT), Option 8 – Onshore HVDC option performs best being £300 million better than Option 3.

Economic sensitivities

The analysis presented above shows the differences in cost-benefit per option. The focus of this chapter is to present some key sensitivity analysis to assess the implications on the conclusions outlined, with the aim being to show the robustness of the result and highlight how changes in the input assumptions may lead to an alternative result. The sensitivities assessed in this chapter includes the impact of:

- Delaying options to 2034
- Change in capital costs
- Change in constraint costs
- Construction of a 2 GW data centre in the East Anglia area

Delay sensitivity

We have also undertaken a sensitivity on delay for the build of the onshore part of the network (as this is the part originally scheduled in 2030), with the capacity instead being delivered in 2032, 2033 or 2034. The last date aligns with when an 'offshore network' is expected to be able to be built.

The table shows the results for Leading the Way.

Total additional cost compared to the chepest overall (Option 3 in 2030)	2030	2032	2033	2034
Option 1	Not delivered	Not delivered	Not delivered	£4,211m
Option 2	Not delivered	Not delivered	Not delivered	£4,832m
Option 3	£0m	£246 m	£781m	£1,643m
Option 4	£2,037	£2,206m	£2,741m	£3,587m
Option 5	Not delivered	Not delivered	Not delivered	£10,340m
Option 5b	Not delivered	Not delivered	Not delivered	£1,422m
Option 6	£1,672	£1,723m	£1,733m	£2,131m
Option 7	Not delivered	Not delivered	Not delivered	£1,794m
Option 8	Not delivered	Not delivered	Not delivered	£962m
Option 9	Not delivered	Not delivered	Not delivered	£8,981m

Table 8: Impact of delaying the delivery date for some options.

Option 3 and Option 4 are the two options with substantive delivery date of 2030. Therefore, they have a delay cost associated with delivering them in 2032, 2033 or 2034. Option 6 is delivered in total in 2034, but there are onshore elements in the hybrid design that are delivered from 2030 onwards so delay over time is shown.

As discussed in the report Option 8 becomes the overall cheapest option if everything is delivered in 2034, with a number of options (Options 3, 5b, 6 and 7) also having comparable lifetime costs.

Capital cost and constraint cost sensitivities

A series of sensitivities to the capital cost (increase and decrease by 20%) and constraint cost (increase and decrease by 40%) show that the results are robust to changes in cost. Although there is some small changes in rankings the overall comparisons remain the same as in the initial analysis.

An increase of 20 per cent in the capital cost

The table below shows the additional costs results updated with an increase of 20% in CAPEX costs for all options.

Total additional cost compared to the best option, per scenario	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£4,839m	£5,111m	£5,145m	£4,808m
Option 2	£5,483m	£6,305m	£5,691m	£5,488m

Option 3	£0m	£0m	£0m	£0m
Option 4	£1,988m	£4,005m	£721m	£1,807m
Option 5	£10,269m	£14,017m	£11,168m	£8,207m
Option 5b	£1,351m	£3,067m	£1,439m	£935m
Option 6	£2,016m	£2,079m	£3,152m	£2,766m
Option 7	£2,115m	£1,737m	£3,157m	£2,329m
Option 8	£1,268m	£5m	£2,746m	£2,053m
Option 9	£9,335m	£12,370m	£5,124m	£9,215m

Table 9: Additional costs updated with an increase of 20% in CAPEX costs for all options

A decrease of 20 per cent in the capital cost

The table below shows the additional costs updated with a decrease of 20% in CAPEX costs for all options.

Total additional cost compared to the best option, per scenario	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£3,584m	£4,463m	£3,889m	£3,552m
Option 2	£4,181m	£5,612m	£4,390m	£4,186m
Option 3	£0m	£608m	£0m	£0m
Option 4	£2,087m	£4,712m	£821m	£1,907m
Option 5	£10,411m	£14,767m	£11,310m	£8,349m
Option 5b	£1,493m	£3,816m	£1,581m	£1,077m
Option 6	£1,329m	£2,000m	£2,465m	£2,080m
Option 7	£1,473m	£1,703m	£2,515m	£1,688m
Option 8	£656m	£0m	£2,133m	£1,440m
Option 9	£8,628m	£12,271m	£4,418m	£8,508m

Table 10: Additional costs updated with a decrease of 20% in CAPEX costs for all options

An increase of 40 per cent in the cost of constraints

The table below shows the additional costs updated with an increase of 40% in constraint costs for all options.

Total additional cost compared to the best option, per scenario	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£4,640m	£6,056m	£5,068m	£4,596m
Option 2	£5,463m	£7,650m	£5,755m	£5,471m
Option 3	£0m	£1,034m	£0m	£0m

Option 4	£2,952m	£6,810m	£1,179m	£2,699m
Option 5	£14,617m	£20,899m	£15,876m	£11,731m
Option 5b	£2,133m	£5,569m	£2,256m	£1,551m
Option 6	£1,655m	£2,778m	£3,246m	£2,706m
Option 7	£1,870m	£2,375m	£3,329m	£2,170m
Option 8	£734m	£0m	£2,803m	£1,833m
Option 9	£11,867m	£17,151m	£5,973m	£11,700m

Table 11: Additional costs updated with an increase of 40% in constraint costs for all options

A decrease of 40 per cent in the costs of constraints

The table below shows the additional costs updated with a decrease of 40% in constraint costs for all options.

Total additional cost compared to the best option, per scenario	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£3,782m	£3,945m	£3,966m	£3,763m
Option 2	£4,200m	£4,694m	£4,325m	£4,203m
Option 3	£0m	£0m	£0m	£0m
Option 4	£1,123m	£2,333m	£363m	£1,015m
Option 5	£6,062m	£8,311m	£6,601m	£4,825m
Option 5b	£712m	£1,741m	£764m	£462m
Option 6	£1,690m	£1,727m	£2,371m	£2,140m
Option 7	£1,718m	£1,491m	£2,343m	£1,847m
Option 8	£1,189m	£432m	£2,076m	£1,660m
Option 9	£6,096m	£7,917m	£3,569m	£6,024m

Table 12: Additional costs updated with a decrease of 40% in constraint costs for all options

New strategic demand sensitivity

For this sensitivity the demand in the region is increased by 2 GW to model something like a large new data centre, or gigafactory. The hypothesis being that more demand locally may change the balance for which option is preferred.

Total additional cost compared to the best option, per scenario	Leading the Way	Consumer Transformation	System Transformation	Falling Short
Option 1	£4,253m	£4,599m	£4,301m	£4,464m
Option 2	£4,524m	£5,029m	£4,530m	£4,599m
Option 3	£0m	£424m	£0m	£0m
Option 4	£1,389m	£3,092m	£490m	£852m
Option 5	£9,132m	£12,652m	£9,894m	£7,286m
Option 5b	£1,588m	£3,430m	£1,546m	£809m
Option 6	£1,853m	£1,838m	£2,515m	£2,357m
Option 7	£2,229m	£1,976m	£2,711m	£2,620m
Option 8	£1,531m	£0m	£1,857m	£1,620m
Option 9	£5,778m	£8,892m	£3,232m	£5,213m

Table 13: CBA with additional demand located in the region

We find that overall, the rankings are broadly robust to the addition of new demand. Under Leading the Way, specifically, Option 3 – Onshore option (most status quo) remains the lowest cost solution overall, but there is a swap for second rank. Option 4 - Alternative onshore option – variation with EACN is now seen as more favourable than Option 6 – Hybrid onshore and offshore option (with EACN) and Option 7 - Hybrid onshore and offshore option – variation without EACN. Other rankings are unchanged.

Appendix 3 – Methodology and further detailed results

This appendix sets out our assessment methodology. This includes further detail on the following:

1. Economic metric methodology
2. Deliverability and operability metric methodology
3. Community metric methodology
4. Environmental metric methodology

Holistic Network Design methodology

To assess options in this study, we followed the metric methodology and strategic options appraisal from the Holistic Network Design (HND) methodology. The HND methodology includes four network design objectives, which considered on equal footing:

- Economic and efficient – The network solution should be economic and efficient.
- Deliverability and operability – The network solution should be reliable, deliverable and operable.
- Environmental impact – Environmental impacts should be avoided, minimised, or mitigated by the network design, and best practice in environmental management should be incorporated into the network design.
- Local community impact – Impacts on local communities should be avoided, minimised, or mitigated by the network design.

The economic assessment uses an economic optimisation tool to determine the net present value (NPV) associated with a specific design The assessment used a combination of financial information about the designs e.g. capital infrastructure costs to determine the value of each design in terms of NPV. The NPV enabled us to compare the economics across each design.

To assess and compare the deliverability and operability, environmental impact and community impact, we used Black, Red, Amber, or Green (BRAG).

Definitions of the BRAG ratings are provided below and remain consistent throughout each stage of the methodology.

- Black – the design is not viable in its current state from an environmental/community/deliverability and operability perspective due to environmental/community/deliverability issues.
- Red – the design has a high level of constraints from an environmental/community/deliverability and operability perspective and is potentially viable, however will have to overcome many environmental/community/deliverability issues.
- Amber – the design has a medium level of constraints from an environmental/community/deliverability and operability perspective and is likely to be viable, however may have to overcome some environmental/community/deliverability issues.
- Green – the design has a low level of constraints from an environmental/community/deliverability and operability perspective and is likely to be viable without any major environmental/community/deliverability issues.

Where this study differentiates from the HND methodology is that it does not make a recommendation, therefore further refinement of options and more detailed factors that could be considered as part of the HND process has not taken place.

Economic metric

The economic analysis has been undertaken by us using our pan-European economic market model, using *Future Energy Scenarios (FES) 2023*[15] as core scenarios, and using boundary capability uplift and capital

[15] download (nationalgrideso.com)

expenditure data that has been received from the Transmission Owner (National Grid Electricity Transmission NGET)). We have benchmarked the costs received.

The lifetime cost assessment uses a 'savings approach' to assess the asset-based options. By assessing the total expenditure over each reinforcement's lifetime, and the associated constraint savings this lifetime cost assessment aims to demonstrate the cost-effectiveness of reinforcement options.

To undertake an economic assessment by:

- Appraising the economic case of the shortlisted options by adopting the Spackman approach and determining respective NPVs across the studied generation scenarios and sensitivities.
- Use the most up-to-date input information available.
- Additional analysis looking at the sensitivity of the cost-benefit assessment (CBA) results to key inputs and assumptions such as the volume and timing of generation and demand projections, constraint volumes and capital expenditure (CAPEX) costs.

The boundaries SC3, LE1, and EC5 are the most heavily loaded in the area of the study, therefore these are the boundaries to be studied to determine the most accurate reduction in constraint costs. This assessment will examine reinforcement of the transmission network in East Anglia, part of NGET's assets.

Network background

Our Network Options Assessment [16](NOA) optimises network capacity for future years based on Transmission Owner submissions of possible reinforcements, future requirements as detailed in the *Electricity Ten Year Statement* (ETYS), and the FES. This produces an optimised network per scenario, and therefore the systems boundary capabilities for each year and scenario. This study uses the output networks of *NOA 2021/22 Refresh*, as published July 2022, as the background for the analysis.

Future Energy Scenario 2023 background

Economic market modelling within this CBA has been undertaken on a *FES 2023* background to evaluate overall transmission constraints. FES is developed with our stakeholders' input to create a range of scenarios highlighting what the future of energy could look like. These have net zero at their core and explore how the level of societal change and speed of decarbonisation could lead to a range of possible future pathways. Three of the scenarios achieve the target of net-zero carbon emissions by 2050, with Leading the Way achieving it ahead of schedule. The scenarios and the axes are shown in Figure 1.

[16] Network Options Assessment (NOA) | ESO (nationalgrideso.com)

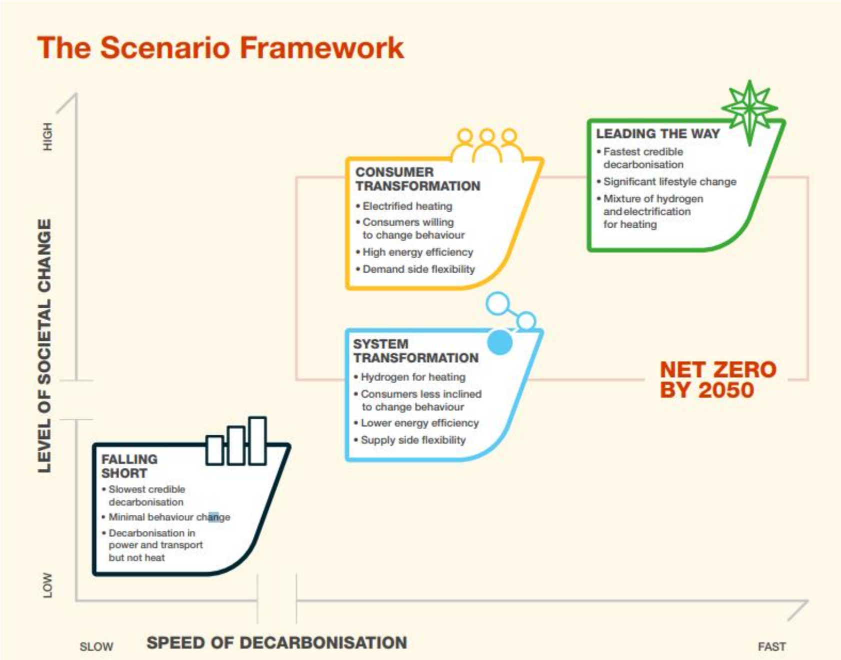

Figure 1: FES 2023 scenario matrix

In our future energy scenarios, to achieve net zero by 2050 will require significantly higher levels of electricity generation; for example, in the 2050 Consumer Transformation scenario, we forecast that Great Britain will have 1.9 times more capacity than it currently has today.

This increase in generation comes in many forms, with a proportion of renewable generation rising in all four scenarios. Bioenergy with carbon capture and storage (BECCS) is included in all net-zero scenarios, with up to 12 GW installed by 2050 in Consumer Transformation. This provides the negative emissions needed to reach net zero across the whole economy. In 2050, four technologies produce over 90 per cent of electricity generation in net-zero scenarios: wind, solar, nuclear and BECCS. In all scenarios:

- Annual electricity demands increase significantly due to combinations of electric vehicles, heat pumps and electrolysis. This means significantly more capacity is required to meet these demands.
- The increase in renewable generation with relatively low annual load factors compared to fossil fuels means significantly more capacity is required to meet demand.
- The weather dependence of renewable generation means that much larger amounts of flexibility are required.

Financing assumptions

Financing assumptions have been adopted to develop Spackman-compliant cost estimates of the options (a way to convert all costs into present values). These estimates include the following assumptions:

- Weighted Average Cost of Capital (WACC), which is currently estimated at 2.81 per cent per annum for NGET.
- Social Time Preference Rate (STPR), based on HM Treasury's Green Book figures of 3.5 per cent for the first 30 years and 3 per cent thereafter for the second 30 years.

This approach is consistent with our usual network planning process methodology.

Our economic market model

The necessary modelling for the CBA is undertaken using our economic market model. It is used to derive constraint costs based upon a given generation scenario and network background.

The model derives future constraint costs in a two-step process. First, it models the future market dispatch based upon whichever plants are most economical to meet demand. Next, it tests the resultant flows implied by the first step against the capabilities of the system boundary limits. If it finds flows are excessive across any boundary, it finds the lowest cost solution to rebalance the network such that no boundary capabilities are being exceeded. This simulates the actions which would be taken by us using the balancing mechanism and trades to keep boundary flows within their limits. The sum of these costs is called the Total Balancing Mechanism (TBM) or Total Constraint Cost (TCC) for that run. The difference in TCC as network capabilities are altered (for instance, through the addition of the options in this assessment) allows us to infer the value of constraint alleviation associated with network development options.

The use of this market model for network planning purposes has been carefully validated through audit and back casting activities. The software has been successfully deployed in our key network development processes, including the Network Options Assessment[17] (NOA).

Deliverability and operability metric

A key part of the appraisal is to review the technical design options and consider their deliverability and operability. Deliverability and Operability means assessing the designs against several aspects such as system complexity, interfaces, technology, planning/consenting and programme.

In addition to being physically deliverable the designs must meet the requirements of the relevant codes and standards[18], including the Security and Quality of Supply Standards (SQSS) and Grid Code (GC). The assessment focuses on reviewing each option, considering:

- Design complexity; technical difficulty in realising a design i.e. interface / landing points, interconnectivity of sites, cabling, and/or offshore substation.
- Construction complexity: To realise the design including potential risks of a particular design option for both onshore and offshore activities.
- Technology Readiness Level: high voltage alternating current (HVAC) is proven design whereas high voltage direct current (HVDC) connections are less mature.
- Planning and consenting complexity both onshore and offshore.
- Supply chain availability, although not a direct limitation to ensure a level of ambition and signal to industry the need to scale up, in consultation with the Deliverability Forum some design options may alter if considered practically infeasible.
- Practical operability of the system, including the control complexity, ability to manages access and power, voltage, and fault management.

To allow comparison between design options, each receives a Deliverability and Operability combined status, known as a BRAG (Black, Red, Amber, Green), based on the assessment considerations above. The ranking goes from Black to Red to Amber then Green. Black ratings are unlikely to progress whereas green are deemed as achievable. The table below defines each of the BRAG ratings across the Deliverability and Operability criteria. This appraisal allows for the determination of possible difficulties, risks and timelines for different aspects of the design. The purpose of the framework is to enable easy comparison of options. Any design option with a Black rating will be excluded and will not be taken forward to the economic assessment process.

[17] Network Options Assessment (NOA) | ESO (nationalgrideso.com)

[18] Codes | ESO (nationalgrideso.com)

Ranking		Deliverability & Operability
●	Black	Highly complex design(s) with new or emergent technology unlikely to be deliverable within the next decade. The design is subject to high likelihood of constraints and risks affecting the construction, consenting and/or operability to such a degree that the option should not be considered further.
●	Red	Design that features some complex elements or technology that may be challenging to deliver. The design is subject to constraints that are likely to affect construction, consenting or operability to such a degree that the option should not be included without potential solutions being identified.
●	Amber	Design of moderate to significant complexity, with constraints or risks which may impact some construction, operability or consents. Design is likely to be achievable and any issues will be straight forward to resolve.
●	Green	Design of low to moderate complexity using proven technology. The design is subject to low likelihood of constraints affecting construction and/or consenting. Option very likely to be achievable without delay.

Table 1: Deliverability and operability metrics

Community metric

The methodology is intended to provide a consistent approach to establishing the likely significance of impacting various community constraints. It will establish the potential feasibility of an area to accommodate a proposed interface point and identify potentially feasible route corridors. It is important to note that the methodology is not intended to determine actual sites or routes, these will only be determined during the detailed network design stage. The assessment methodology effectively involves four levels of rating/ranking based on different BRAG (Black, Red, Amber, Green) criteria relevant to each stage, namely;

- The rating of individual constraints based on their potential to constrain the deliverability of the option if impacted by that option.
- The ranking of individual aspects of the proposed options, interface points and cable route corridors, which takes account of the number and level of constraints intersected.
- A final overall ranking of options which will amalgamate the rankings of the individual aspects of the option i.e. interface points and cable route corridors, to give a single relative ranking for the option thus enabling options to be compared.

The overall aim of the methodology, is to robustly implement the established mitigation strategy of Avoid, Reduce, Mitigate. A strong focus on Avoid and Reduce is applied during the early stages of the overall methodology, with mitigation considered where required in the final options appraisal, considering the level that this can be undertaken in a strategic study without detailed survey and routing information.

Publicly available environmental and community onshore and offshore constraint mapping data is used to assess the options, while not excluding physical infrastructure such as major roads, gas transmission infrastructure, major developments and urban areas.

The constraint analysis is informed by a series of principles, covering issues such as allowable proximity, features to avoid etc. all of which are used ultimately to assign a weighting or rating to each constraint and while there are established methodologies for locating substations and overhead lines in the UK known respectively as the Horlock and Holford Rules[19], there are no published methodologies for the location of buried cables onshore or offshore. However, due to the number of such infrastructure developments constructed in the UK, there is a wealth of experience that can be utilised to establish constraint requirements for these.

[19] https://www.nationalgrid.com/sites/default/files/documents/13796-The%20Horlock%20Rules.pdf
https://www.nationalgrid.com/sites/default/files/documents/13795-The%20Holford%20Rules.pdf

The approach for appraising the options was on an area basis. This is where an area of study will be identified that the onshore & offshore options are to be located within. An appraisal was then made, on how much the environment and community constraints within that area constrain the development of the individual option being appraised.

The main reason for this approach was due to the level of information available on the options, which will not be strong enough to define any particular corridors. Hence, a broader approach of appraising on an area basis is required.

Community Constraints	Description
Landscape and visual	
National Parks	Areas of the UK established and receiving statutory protection via the National Parks and Access to the Countryside Act
National Landscapes	National Landscapes (previously known as Areas of Outstanding Natural Beauty ANOBs)
National Trails	National Trails are long distance walking, cycling and horse-riding routes through the best landscapes in England and Wales.
Heritage Coasts	A non-statutory designation established to conserve the best stretches of undeveloped coast in England.
Historic Environment	
World Heritage Sites	United Nations Educational, Scientific and Cultural Organisation (UNESCO) designation for sites of outstanding universal value – cultural and/or natural significance which are so exceptional as to transcend national boundaries and to be of common importance for present and future generations of all humanity.
Scheduled Monuments	Nationally important archaeological sites and monuments
Listed Buildings	Protection of a building's special architectural and historic interest.
Protected wrecks	A restricted area around a wreck, designated to prevent uncontrolled interference.
Registered Parks and Gardens	Designed landscapes that are considered to be of national importance
Registered Battlefields	Important battlefields that are considered to be of national significance
Wreck locations	Location of known wrecks around the UK.
Ship Hulk	Location of ship hulks (i.e. old ships stripped of their fittings and permanently moored in intertidal areas, estuaries, canals, and rivers, often in a condition too dilapidated to return to sea).
Air Quality	
Air Quality Management Area (AQMA)	An area designated under the Environment Act 1995 by a local authority, where national air quality objectives are not likely to be achieved.
Noise	
Major Settlements	Urban areas consisting of major urban agglomerations, cities and small towns.

Community Constraints	Description
Small Scale Settlements[3]	Any settlement smaller than a small town (e.g. villages, hamlets).
Socio-economic	
Major Settlements	Urban areas consisting of major urban agglomerations, cities and small towns.
Small Scale Settlements	Any settlement smaller than a small town (e.g. villages, hamlets).
National Trust Land	Land owned by the National Trust.
Royal Yachting Association (RYA) sailing and racing areas	Areas identified by the RYA as being used for sailing and racing by their members.
Bathing waters	Surface waters designated as bathing water by the Bathing Water Regulations 2013. Bathing waters are monitored, and water quality classified as Excellent, Good, Sufficient or Poor.
Fishing activity	Areas calculated as having high intensity fishing effort.
Marine Fish Farms	Locations of marine fish farms in the UK.

Table 2: Community metrics considered for this study

Environment metric

The methodology is intended to provide a consistent approach to establishing the likely significance of impacting various environmental constraints. It will establish the potential feasibility of an area to accommodate a proposed interface point and identify the constraints and viability of potential route scenarios. It is important to note that the methodology is not intended to determine actual sites or routes, these will only be determined during the detailed network design stage.

The assessment methodology effectively involves four levels of rating/ranking based on different BRAG criteria relevant to each stage, namely;

- The rating of individual constraints based on their potential to constrain the deliverability of the option if impacted by that option.
- The ranking of individual aspects of the proposed options, interface points and cable route corridors, which takes account of the number and level of constraints intersected.
- A final overall ranking of options which will amalgamate the rankings of the individual aspects of the option i.e. interface points and cable route corridors, to give a single relative ranking for the option thus enabling options to be compared.

The overall aim of the methodology is to implement the established mitigation strategy of Avoid, Reduce, Mitigate. A strong focus on Avoid and Reduce is applied during the early stages of the overall methodology, with mitigation considered where required in the final options appraisal, considering the level that this can be undertaken in a strategic study without detailed survey and routeing information.

Publicly available environmental and community onshore and offshore constraint mapping data is used to assess the options, while not excluding physical infrastructure such as major roads, gas transmission infrastructure, major developments and urban areas.

The constraint analysis is informed by a series of principles, covering issues such as allowable proximity, features to avoid etc. all of which are used ultimately to assign a weighting or rating to each constraint and while there are established methodologies for locating substations and overhead lines in the UK known respectively as the Horlock and Holford Rules[20], there are no published methodologies for the location of buried cables onshore or offshore. However, due to the number of such infrastructure developments constructed in the UK, there is a wealth of experience that can be utilised to establish constraint requirements for these.

The approach for appraising the options was on an area basis. This is where an area of study will be identified that the onshore & offshore options are to be located within. An appraisal was then be made on how much the environment and community constraints within that area constrain the development of the individual option being appraised.

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Environmental Constraints	Description
Ecology – International / European designations	
Special Area of Conservation (SAC) / proposed Special Area of Conservation (pSAC)	Conservation sites that make a significant contribution to conserving the habitats and species
Special Protection Area (SPA) / proposed Special Protection Area (pSPA)	Protected areas for specified bird species
Sites of Community Importance (SCI)	Sites that were adopted by the European Commission before the end of the Transition Period following the UK's exit from the EU, but not yet formally designated by the government of each country.
Ramsar sites / proposed Ramsar Sites	Wetlands of international importance designated under the UNESCO Ramsar Convention.
Important Bird Areas (IBA)	Areas identified by BirdLife International that have significance for the international conservation of bird populations.
Biosphere Reserves	Non-statutory areas identified for testing interdisciplinary approaches to understanding and managing changes and interactions between social and ecological systems.
Ecology – National designations	
Site of Special Scientific Interest (SSSI)	Predominantly terrestrial and coastal areas designated due to their flora, fauna, geological, geomorphological or physiographical features.
National Nature Reserve (NNR)	Predominantly terrestrial sites established to protect the most significant areas of habitat and of geological formations.
Marine Conservation Zones	A type of marine protected area that protect a range of nationally important, rare or threatened habitats and species.
Highly Protected Marine Areas (HPMA)	Areas of the sea designated for the protection and recovery of marine ecosystems.
Ecology – Local designations	

[20] Microsoft Word - The Holford Rules.doc (nationalgrid.com)

Environmental Constraints	Description
Ancient Woodlands	An area that's been wooded continuously since at least 1600 AD. The habitat is considered to be irreplaceable.
Royal Society for the Protection of Birds (RSPB) Reserves	Non-statutory sites established as reserves by the RSPB.
Ecology - Habitats	
Annex 1 Reefs outside designated areas	Habitats listed in the European Community Habitats Directive to ensure they are maintained or restored.
Annex 1 Sandbanks outside designated areas	
Annex 1 Submarine Structures outside designated areas	
Annex 1 Saltmarsh outside designated areas	
Ecology – Species	
UK Grey Seals	Protected by the European Community Habitats Directive and afforded statutory status in the UK.
UK Harbour Seals	
SCANS 3 (marine mammal densities)	Large scale ship and aerial survey to study the distribution and abundance of cetaceans (whales, dolphins and porpoises) in European Atlantic waters.
UK Seabirds at Sea	A dataset containing survey data covering much of the UK waters of interest, covering Seabirds and their nests.
Fish Spawning Grounds	Marine Areas more sensitive to human activity and disturbance.
Fish Nursery Grounds	
Geology and soils	
Geoparks	Non-statutory UNESCO designation of areas with internationally important rocks and landscapes.
National Flood Zones	Areas defined nationally by the Environment Agency as being at risk from flooding from rivers or the sea.
Historic Landfill Sites	Sites previously used as landfill sites and receiving a variety of different types of waste, but which are now closed.
Peatland	Peat is organic material that has built up in waterlogged conditions over thousands of years and represents a large store of carbon captured from the atmosphere.
Socio-economics	
Shellfish waters	Protected areas designated by the Water Environment.

Table 3: Environmental metrics