Offshore Coordination Phase 1 Final Report

Published Date - 16 December 2020

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Executive summary

Welcome to our final Phase 1 report on the costs and benefits of a more coordinated approach to connecting offshore electricity infrastructure. This document also includes a report on holistic planning of the offshore transmission network and proposals for changes to the offshore connections regime. All elements of this report have been shaped by feedback received through our offshore coordination consultation this autumn.

Our 2020 *Future Energy Scenarios*[1] (FES) suggest between 83 and 88 GW of network-connected wind is needed by 2050 in order to deliver the net zero greenhouse gas emissions target[2]. Around 10 GW of offshore wind has been installed in Great Britain, primarily over the last decade. Delivering the anticipated levels would require more than quadrupling the pace at which that was delivered and up to an eightfold growth in overall scale.

The number of interconnectors with other countries is also projected to rise, with the FES including up to 27 GW by 2050, up from 6 GW today.

Further to this, the Climate Change Committee's Sixth Carbon Budget, published in December 2020, recommends the UK develop a strategy to coordinate interconnectors and offshore networks for wind farms and their connections to the onshore network, as part of its advice to ministers on the volume of greenhouse gases the UK can emit during the period 2033-2037[3].

One of the challenges to delivering the ambition in the timescales required will be ensuring that the offshore and onshore transmission network enables this growth in a way that is efficient for consumers and takes account of the impacts on coastal communities and the environment.

The ESO Offshore Coordination project forms part of the Department of Business, Energy and Industrial Strategy (BEIS) Offshore Transmission Network Review[4] (OTNR). We launched our consultation on 30 September 2020 to seek stakeholders' feedback on our approach to this analysis and subsequent findings.

1 www.nationalgrideso.com/document/173821/download
2 The Leading the Way scenario also includes 24GW of offshore wind used directly to produce hydrogen, which we have not considered in our assessment as we have only focused on the capacity connected to the electricity transmission system.
3 www.theccc.org.uk/publication/sixth-carbon-budget/ as a footnote
4 www.gov.uk/government/groups/offshore-transmission-network-review

Executive summary

Thank you to all who engaged in this process and provided valuable feedback.

In response to feedback on the practicalities of commencing integration from 2025, we conducted a new sensitivity analysis on the impact of commencing integration in 2030, compared to integration commencing in 2025, as in our original analysis. This confirms that there is significant benefit in moving quickly to an integrated network and the importance of considering what flexibility there is for coordination between 2025 and 2030. The key messages in this report are:

- Adopting an integrated approach for all offshore projects[5] to be delivered from 2025 has the potential to save consumers approximately £6 billion, or 18 per cent, in capital and operating expenditure between now and 2050.
- There are also significant environmental and social benefits with an integrated approach, as the number of new electricity infrastructure assets, including cables and onshore landing points, could be reduced by around 50 per cent.
- Delivering the extent of integration required in this timescale would be extremely challenging and potentially risk meeting the target of 40 GW of offshore wind by 2030. However, the benefits reduce the later integration begins.
- An integrated approach for projects to be delivered from 2030, compared to the status quo, would deliver savings to consumers of around £3 billion (or 8 per cent[6]) and could facilitate a 30 per cent reduction in the new electricity assets associated with these offshore connections.
- There is therefore a need to deploy innovative and flexible approaches to the connection of offshore wind in the intervening period until a new enduring, integrated, approach is in place. This would be with the aim that, as much as possible, the benefits of an integrated approach can be captured for consumers and communities without placing the delivery of projects underway and the 2030 offshore wind target at undue risk.
- The increased levels of offshore wind mean there will be an increase in onshore infrastructure in all options, including, and potentially beyond, that set out in the 2020 *Network Options Assessment* (NOA[7]). However, adopting an integrated approach across the onshore and offshore networks can minimise the overall increase.
- The majority of the technology required for the integrated design is available now or will be by 2030. However, a key component to release the full benefits of an integrated solution are high voltage direct current (HVDC) circuit breakers. A targeted innovation strategy in the UK, along with support for early commercial use, could help progress HVDC circuit breakers to commercial use and establish Great Britain as a world leader in offshore grids.
- There is a need for all parties to work collaboratively and at pace to enable Great Britain to achieve its offshore wind targets and net zero ambition at least cost to consumers and with least impact on communities and the environment.

5 This means applying an integrated approach to all offshore projects that have not yet received consent.
6 The values and percentage figures for consumer savings have been rounded for the purpose of the final Phase 1 report. Full figures are available in the Cost-Benefit Analysis Report.
7 www.nationalgrideso.com/research-publications/network-options-assessment-noa

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Executive summary

This first phase of work lays the foundations needed by the OTNR partners and a wide range of organisations to identify the steps and take the decisions needed for an integrated approach to an offshore transmission network. We recognise that, following the publication of this report, any subsequent steps will require a collaborative approach across a wide range of parties to progress an integrated approach. This will help collaboratively achieve the commitments in the Energy White Paper to progress a new offshore transmission regime from 2030 and encourage projects delivering before then to consider the opportunities for coordination[8].

Phase 2 of our offshore coordination project, commencing at the start of 2021 (See page 40), intends to deliver those ESO-led actions required to help achieve the vision set out in Phase 1.

We look forward to continuing to work with you, as together, we progress towards greater offshore coordination, helping to facilitate a zero-carbon future in a way that delivers economic benefits and minimises the impacts on coastal communities and the environment.

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8 www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

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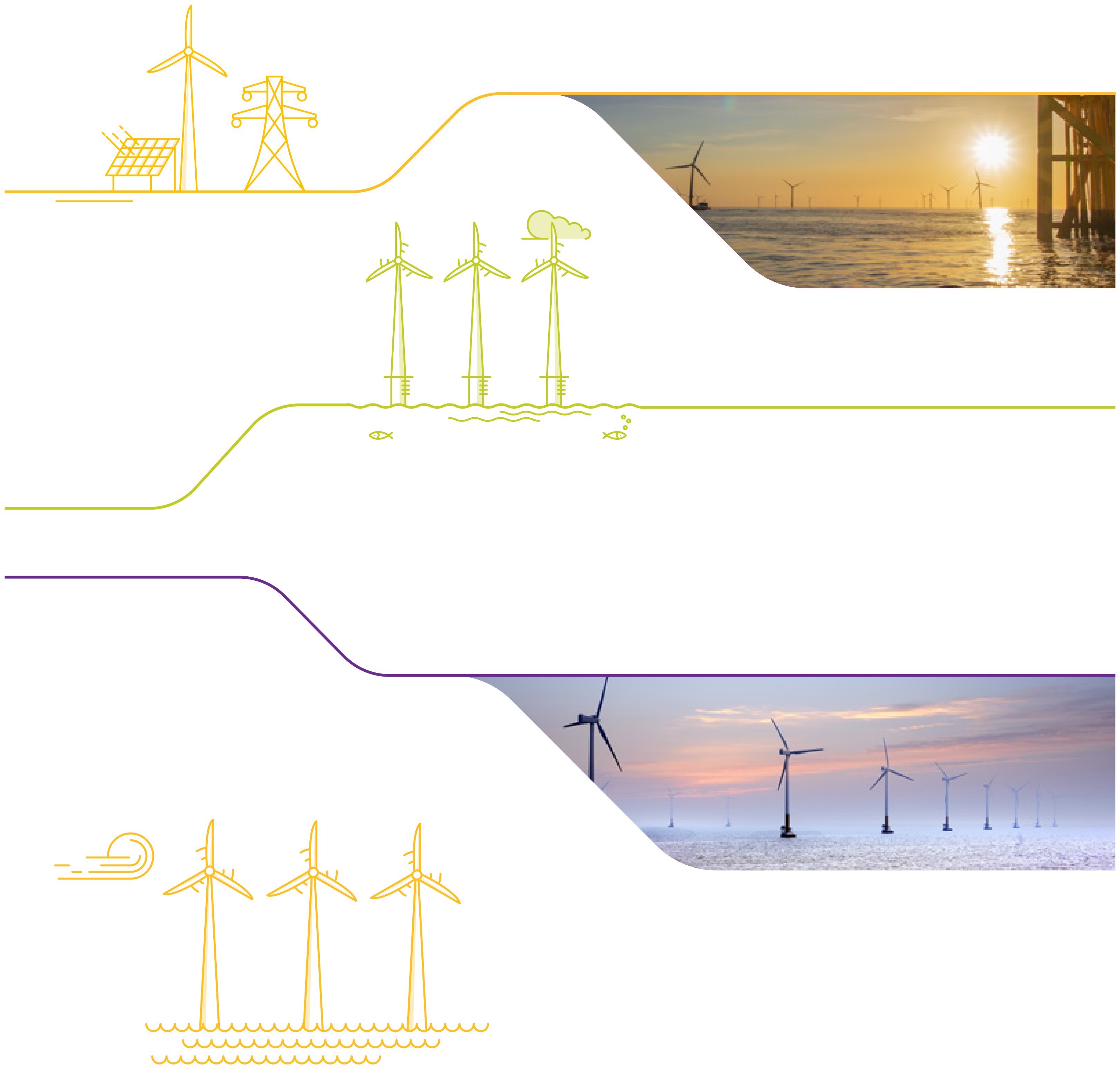

Introduction

The current approach to designing, building and connecting offshore wind farms was developed when the technologies involved were at the early stages of deployment at scale. Regulation was designed to de-risk the delivery of offshore wind by providing project developers with the option of building the associated transmission assets to bring the energy onshore. To date, the existing offshore regime has connected 10 GW of offshore wind to the Great Britain electricity system; a third of the world's installed offshore wind capacity. The current regime for developing and connecting offshore wind generation incentivises developers to connect individually, with competition used to reduce costs rather than promote coordination. It is now uncertain whether the existing regime can deliver the current levels of ambition in the timescales required, in a way that is efficient for consumers and appropriate for coastal communities and the environment.

In February 2020 Ofgem published its Decarbonisation Action Plan[1], which set out a number of actions for them. Through Action 3, Ofgem committed to exploring a more coordinated, efficient system of offshore transmission and, more specifically, to working with us to ensure we rigorously assess the options for coordination of offshore transmission and analysis on the likely costs and benefits, which this final report fulfils. On 15 July 2020 the Minister for Business, Energy and Clean Growth launched the Offshore Transmission Network Review[2] (OTNR). The review brings together the organisations with a key role in this area, including Ofgem, the Crown Estate and ourselves. The objective of the OTNR is to identify the most appropriate way to deliver the transmission infrastructure for offshore wind farms; balancing environmental, social, and economic costs and benefits.

This final report builds on our consultation of 30 September[3] and takes account of the valuable feedback provided in response to that. Detailed information on the feedback we received and how we have responded to it can be found in our stakeholder annex with summaries included in the relevant sections of this report.

This report sets out a vision and assessment of a conceptual integrated network, providing evidence to inform the other workstreams of the OTNR. To progress to an integrated approach, changes needed to the current regime will need to be established and a plan developed to confirm and implement subsequent steps. This will help collaboratively achieve the commitments in the Energy White Paper to progress a new offshore transmission regime from 2030 and encourage projects delivering before then to consider the opportunities for coordination.

The designs we set out in this final report and supporting material are conceptual and based on the ESO future energy scenario, Leading the Way. This scenario was selected as it closely aligns with the Government's ambition for 40 GW of offshore wind by 2030 as well as net zero by 2050. The network designs in our final report build on the already planned onshore network reinforcement set out in the *Network Options Assessment*[4], which includes and goes beyond the onshore developments currently progressing through the planning and consenting process[5]. Further analysis and design, along with an appropriate legislative and regulatory model, will be required to take these from a concept, to a plan, to reality and therefore realise the potential benefits we set out in this document.

1 www.ofgem.gov.uk/publications-and-updates/ofgem-s-decarbonisation-action-plan
2 www.gov.uk/government/publications/offshore-transmission-network-review
3 www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/documents
4 www.nationalgrideso.com/research-publications/network-options-assessment-noa
5 Details of the onshore network reinforcement assumed to be in place in addition to that set out in the network designs can be found in the Assumed network reinforcements annex on page 44.

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Introduction

Realising the benefits of an integrated offshore network

With the required pace of development[6], the greatest benefits will be seen from taking forward an integrated approach as early as possible. Our core analysis assumes that there is integration from 2025, and this is what would be an ideal scenario to deliver maximum integration. However, from a practical point of view, some of the assumed integration in these earlier years will be difficult in reality, where projects are already at an advanced stage of development. Some stakeholders have been clear that the changes required to deliver an integrated offshore network from 2025 risk delaying implementation, resulting in the 2030 offshore wind target being missed. As full integration before 2030 will be difficult and complex therefore changes will need to happen in a phased way for projects connecting in that period.

In response to stakeholder feedback, we have carried out sensitivity analysis to assess the benefit from integration commencing in 2030. This means our analysis now covers two integrated approaches; Integrated 2025, the approach set out in our consultation document, and the new Integrated 2030 with the later start date for integration. As is set out later in this document, the analysis of the Integrated 2030 approach confirms that there is real benefit in moving quickly to an integrated offshore network solution. However, it should be noted that there is still benefit from taking an integrated approach from 2030, compared to the status quo.

Many projects due to connect ahead of 2030 have connection agreements already in place and in line with existing regulatory and licence arrangements we are working with the relevant Transmission Owners (TOs) and developers to continue to progress on the basis of those agreements. However, we appreciate there may be appetite from some developers for a voluntary opt in approach and would welcome discussions with any developers who are interested in exploring that as an option. Similarly, building on their open letter earlier in the year, BEIS and Ofgem are seeking interest as part of their pathfinder projects. In our proposed Phase 2 of this project we plan to look at how we can work with developers and TOs to enable a level of coordination with some projects that already have connection agreements. This will link into BEIS and Ofgem's pathfinder projects.

6 www.ofgem.gov.uk/publications-and-updates/increasing-level-coordination-offshore-electricity-infrastructure-beis-and-ofgem-open-letter-developers-offshore-wind-generation-electricity-transmission-licensees-and-other-interested-parties

Introduction

1 Cost-Benefit Analysis

2 Holistic Approach

3 Connections process review

This document sets out our views in three areas:

1. Cost-Benefit Analysis of a more coordinated offshore network compared to the current individual, radial approach.
2. Holistic Approach to Offshore Transmission Planning.
3. Recommended changes to the offshore connections process.

Sensitivity Analysis

Document overview:

This document provides a summary of these reports and highlights the key messages from them. For each of these areas, supporting reports are available.

How it all fits together:

Cost-Benefit Analysis Report*	Holistic Approach to Offshore Transmission Planning Report	Offshore Connections Review Report
Inputs	Inputs	Inputs
• Environmental impacts • Local authority survey • Stakeholder views	Conceptual designs of GB network Technology unit costs Power system analysis	Internal & external stakeholder input

Sensitivity Analysis

*The full CBA framework can be found in the full report.

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Navigating the final documentation for Phase 1

1 COST-BENEFIT ANALYSIS

KEY MESSAGES
five minute read

SUMMARY OF FINDINGS
30 minute read

FULL DETAILED REPORT
1hr + read

2 OFFSHORE TRANSMISSION PLANNING

KEY MESSAGES
five minute read

SUMMARY OF FINDINGS
30 minute read

FULL DETAILED REPORT
1hr + read

3 OFFSHORE CONNECTIONS REVIEW

KEY MESSAGES
five minute read

SUMMARY OF FINDINGS
30 minute read

FULL DETAILED REPORT
1hr + read

SENSITIVITY ANALYSIS
FULL DETAILED REPORT
1hr + read

This document provides a summary of these reports and highlights their key messages. For each of these areas, supporting reports are available. Please note that the technology unit cost information has been removed from the 'Holistic Approach to Offshore Transmission Planning' report as it is confidential.

We have published a new Sensitivity Analysis Report. The key messages and findings for this report are within the Cost-Benefit Analysis and Holistic Approach to Offshore Planning sections in this document but each have their own separate detailed report.

To view the glossary click here

To view a summary of changes in our detailed reports click here

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Key messages

Key messages

Overarching

- This report is the first step within the BEIS-led Offshore Transmission Network Review (OTNR). Decisions and actions to move from a vision into a plan and reality will need to progress collaboratively and at pace to enable Great Britain to achieve its offshore wind targets and net zero ambition at least cost to consumers and with least impact on communities and the environment.
- Delivering the extent of integration proposed in this report in short timescales would be extremely challenging and potentially risk meeting the target of 40 GW of offshore wind by 2030. However, the benefits reduce the later integration begins.
- There is therefore a need to deploy innovative and flexible approaches to the connection of offshore wind in the intervening period until a new enduring, integrated, approach is in place. This would be with the aim that, as much as possible, the benefits of an integrated approach can be captured for consumers and communities without placing the delivery of projects underway and the 2030 offshore wind target at undue risk.

Cost-Benefit Analysis

- Adopting an integrated approach for all offshore projects[1] to be delivered from 2025 has the potential to save consumers approximately £6 billion, or 18 per cent, in capital and operating expenditure between now and 2050.
- There are also significant environmental and social benefits with an integrated approach, as the number of new electricity infrastructure assets, including cables and onshore landing points, could be reduced by around 50 per cent.
- An integrated approach for projects to be delivered from 2030, compared to the status quo, would deliver savings to consumers of around £3 billion (or 8 per cent[2]) and could facilitate a 30 per cent reduction in the new electricity assets associated with these offshore connections.

> **We believe that there is now strong consensus among key stakeholders that the UK needs to move towards a radically different model of delivering offshore wind, fully embracing coordination, if we are to maintain our prime position as a global leader in offshore wind and – above all – deliver our ambitious targets for green energy generation**
>
> *- Community representative*

1 This means applying an integrated approach to all offshore projects that have not yet received consent.
2 The values and percentage figures for consumer savings have been rounded for the purpose of the final Phase 1 report.

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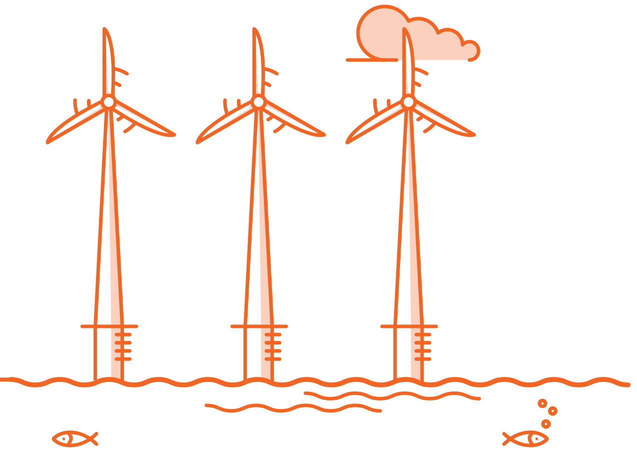
Key messages

Holistic approach to offshore planning

- The increased levels of offshore wind mean there will be an increase in onshore infrastructure in all options, including, and potentially beyond, that set out in the 2020 *Network Options Assessment* (NOA)[3]. However, adopting an integrated approach across the onshore and offshore networks can minimise the overall increase.
- The majority of the technology required for the integrated design is available now or will be by 2030. However, a key component to release the full benefits of an integrated solution are high voltage direct current (HVDC) circuit breakers. A targeted innovation strategy in the UK, along with support for early commercial use, could help progress HVDC circuit breakers to commercial use and establish Great Britain as a world leader in offshore grids.

> **The Integrated network designs proposed for 2030 and 2050 are merely indicative best views of hypothetical integration, there is still a need for a realistic roadmap of action to be developed taking into account other key commercial and regulatory barriers that will have an impact on the final coordinated design.**
>
> *- Offshore developer*

Offshore Connections Review



- Changes to the offshore connection regime – including to the assessment process for the location of offshore connections (the CION[4]) and packaging connection offers with other elements of the process – will encourage and drive more coordination in the short, medium and long term.

> **With net zero by 2050 now legally required, and a dramatic expansion of the UK offshore energy target to 40 GW by 2030, it is now widely accepted in the industry that the way offshore wind capacity is configured needs to radically change.**
>
> *- Community representative*

3 www.nationalgrideso.com/research-publications/network-options-assessment-noa
4 www.nationalgrideso.com/document/45791/download

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Consultation feedback

In October 2020 we consulted with you on the work completed to date to shape our final documentation for Phase 1 ahead of commencing further work required to realise the vision of an integrated network set out.

Lots of you took the time to get involved in our interactive workshops, meet with us and respond in writing to the consultation. Many thanks to all of those who took the time to get involved; the feedback received has all been considered in the preparation of our final documents.

1
Launch webinar

40
Written responses

11
Interactive workshops

76
Organisations

> **We are also very grateful to National Grid Electricity System Operator (NGESO) for its sustained and effective engagement during the development of this project and during the consultation.**
>
> *- Community representative*

We have provided a summary at the start of each of the areas of this overarching report that provides an overview of what has changed in our three reports based on your feedback. We have also published a stakeholder annex[1], which includes more detailed feedback and responses to some of the questions raised.

The overarching themes from the feedback we received are captured below:

- There is widespread support for offshore coordination. Those representing coastal communities are keen to see progress as rapidly as possible. Other stakeholders cautioned against the difficulty in doing so due to the impact on projects already in progress.
- A strong message emerged on the need for regulatory and legislative regime changes to enable offshore coordination and a need to consider the practicalities onshore, offshore and with technology maturity.
- Stakeholders were generally positive about the approach we have taken and our findings, with information provided to help refine our analysis.

Your feedback has shaped the scope of our work for Phase 2 of the project. You have provided constructive ideas on how we can further develop the work completed to date and an overview of the next phase of the project can be found in the What Happens Next? section of this report (See page 40). We will be seeking views from interested stakeholders on the detail of this and we are looking forward to working in collaboration with you throughout 2021 to start to realise the vision set out in Phase 1 of the project.

Your feedback also covered the roles that other organisations could play to help move from the vision set out as part of Phase 1 to reality. These areas have been highlighted to the relevant organisations whilst maintaining the indicated confidentiality of responses.

1 www.nationalgrideso.com/document/182921/download

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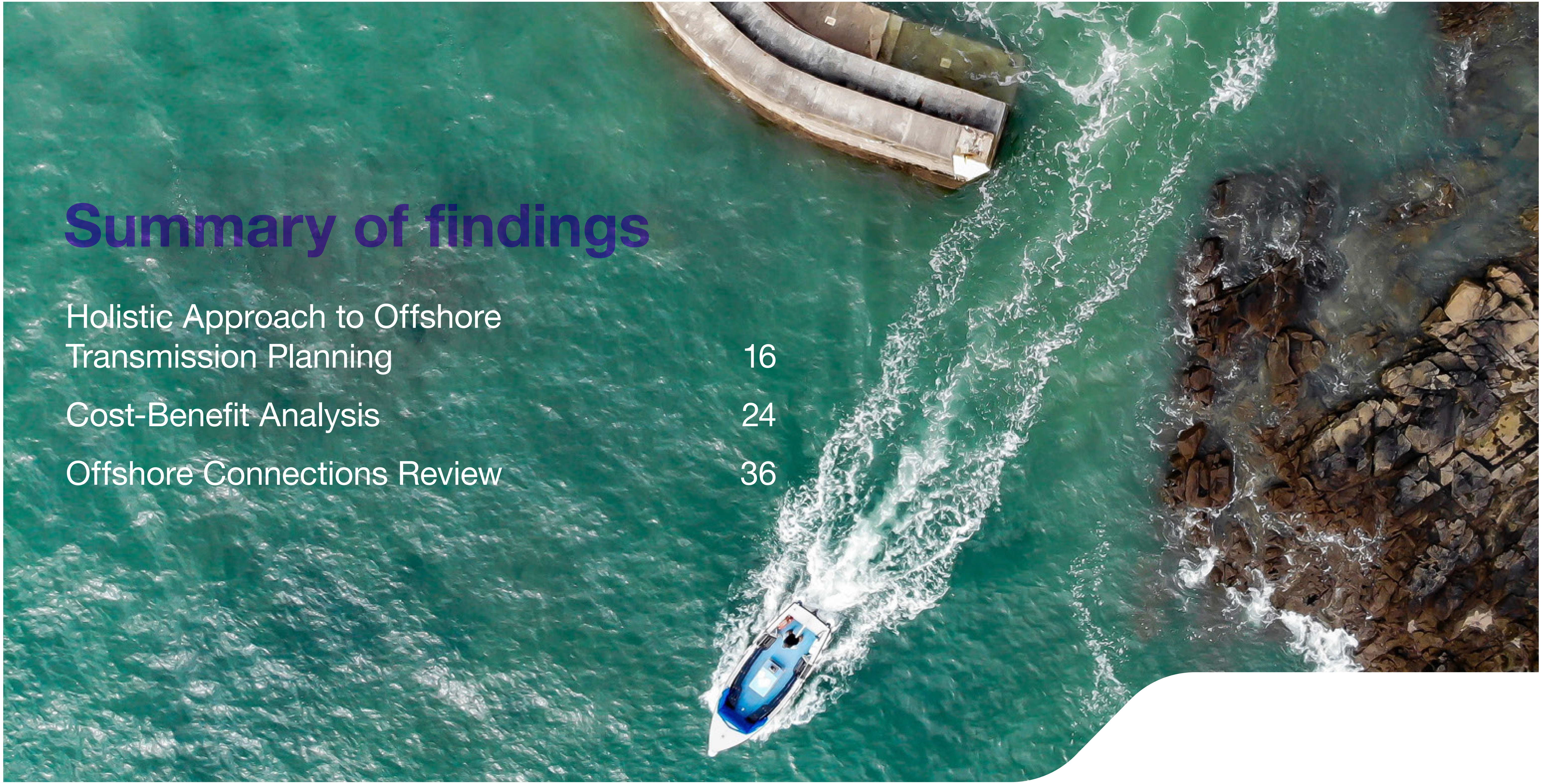

Summary of findings

Summary of findings

Holistic Approach to Offshore Transmission Planning

Stakeholder feedback

We received a number of positive responses to our consultation in October and the feedback has helped to confirm the content of the final Holistic Approach to Offshore Transmission Planning Report. The way we have acted upon your feedback is summarised below:

- The majority of feedback received on this report were suggestions for future work. This, including the questions and statements that relate to environmental impacts (onshore and marine), have been taken into consideration for our next phase of work.
- A number of questions were about our assumptions on technology readiness and we have followed up individually with respondents to address these. We believe we have been realistic about the technology likely to be available by 2030 and we have based our designs on these assumptions.
- To address questions on which onshore investments were taken as being built in advance of our designs, we have now provided a table in the assumed network reinforcements annex (See page 44), which presents the investments that are included in the baseline network for our studies.
- Some of the feedback received was valuable but was out of scope for the ESO, for example relating to the wider offshore regime, commercial and regulatory principles. This has been shared with the relevant government bodies.

> **The volume of work required to transition to an integrated offshore system, and then the design and management of that system, should not be underestimated.**
>
> *- Trade body*

> **Without a new approach and careful planning for an integrated approach, there will be serious negative impacts on the marine environment and potential consenting barrier.**
>
> *- Environmental representative*

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Summary of findings

The Holistic Approach to Offshore Transmission Planning Report assesses and presents conclusions on the key areas of technology and technical consideration related to the design of integrated offshore networks. The findings from this report have informed the subsequent Cost-Benefit Analysis that has been completed.

This report has been developed by experts in this field and has incorporated feedback provided by stakeholders throughout its development.

A high-level overview of the key content of the report and the insights from these areas can be found in the following pages. A fuller explanation of all the technical analysis completed and the resulting findings and conclusions can be found in the report itself.

Overview of the integrated network options compared to the status quo

For our analysis, we defined three alternate approaches to connecting the levels of offshore wind capacity set out in the FES Leading the Way (LW) Scenario. The first two of these set out a vision of how an integrated network could look if integration commences from 2025 and 2030.

This is shown for 2030 and 2050 for the Integrated 2025 option, and just 2050 for the Integrated 2030 option, with 2030 being the same as the status quo. These were compared to maintaining the status quo, which extrapolates current project activity into the future, primarily using radial high voltage alternating current (HVAC) and HVDC connections.

Both integrated options connect a number of individual wind farms located in a similar geographical area, via the shared use of offshore transmission infrastructure. As would be expected, there is most opportunity for integration where new wind farms and interconnectors are located in a similar geographical area. For the Integrated options the impact on the onshore network is minimised as electricity can be more readily transported via offshore cables closer to the areas of demand, than for the status quo option.

A summary of the differences between design approaches for the status quo and Integrated options are set out in Table 1.

Status quo – Project by project transmission build up	Integrated – Transmission asset sharing enabled
Requirements for each project considered separately	Takes account of possible future requirements
Only considers point-to-point offshore network connections	Considers a range of connection options including multi-terminal/ meshed HVDC and HVAC options
Individual project optimisation and transmission (HVAC or HVDC) decision	Considers whole system optimisation and transmission technology decisions
Onshore and offshore network designs are considered separately	Considers effect on onshore system as part of offshore design development
Interconnectors are designed and connected separately	Possibility that interconnector/ bootstrap capacity can be shared by an offshore wind farm
Local community impacts are managed on a project by project basis	Local community impacts considered on an overall impact basis

Table 1 Design approaches for the status quo and Integrated options

Summary of findings

These high-level design approaches have been used to provide an indicative view of what could be possible with the current and projected technology available and in line with the current network security standards.

Turning these into detailed designs, with specific routes and landing points, would require further detailed analysis and data inputs. For example, this could include the consideration by location of onshore and offshore environmental constraints, the economics and practicalities of connecting to the onshore network at specific landing points, the suitability of the seabed to accommodate cabling, more detailed analysis on the impact on system operability, the deliverability from a consenting and supply chain point of view and the impact on local communities and the environment. We are proposing we consider many of these in our Phase 2 work as we analyse an integrated network in greater detail.

For all approaches we have assumed that the Government's ambition for 40 GW of offshore wind by 2030 is met, 83 GW of transmission-connected offshore wind is in place by 2050, 22 GW interconnectors are in place in 2030 and 27 GW in 2050. The Leading the Way scenario includes 108 GW offshore wind overall. The 83 GW included in the network designs excludes the 24 GW of offshore wind that transports its energy to land as hydrogen, uses other storage technologies offshore, or powers offshore demand such as oil and gas platforms[1].

To perform our analysis, we split the waters around Great Britain into six regional offshore wind development zones. Figure 1 shows the regional installed offshore wind capacities from 2020 to 2050 in Leading the Way.

LW Scenario Total Installed Capacity

- 2050 → 83.1 GW
- 2030 → 42.0 GW
- 2025 → 23.9 GW
- 2020 → 9.6 GW

North Scotland	
2050	18 GW
2030	6.5 GW
2025	2.5 GW
2020	0.8 GW

N Wales & Irish Sea	
2050	15.4 GW
2030	3.7 GW
2025	2.7 GW
2020	2.7 GW

East Scotland	
2050	9.3 GW
2030	5.1 GW
2025	2.8 GW
2020	0 GW

Dogger Bank	
2050	10.8 GW
2030	7.6 GW
2025	4.5 GW
2020	0.4 GW

Eastern Regions	
2050	27.5 GW
2030	17.4 GW
2025	10.1 GW
2020	4.4 GW

South East	
2050	2.1 GW
2030	1.7 GW
2025	1.3 GW
2020	1.3 GW

Figure 1 Regional installed offshore wind capacity up to 2050

1 www.nationalgrideso.com/future-energy/future-energy-scenarios

Summary of findings

2030: High-level comparison of the Integrated 2025 network option to the status quo

Figure 2 compares the Integrated (just for the 2025 start date) and status quo approaches in 2030. The Integrated 2030 option will look the same as the status quo in 2030. Similarly, Figure 3 compares them in 2050 and includes all three options. For both timeframes, the maps set out for an incremental level of growth from 2025 onwards and how the Integrated 2025 and status quo options result in different overall solutions for connections to the Great Britain onshore network.

In 2030, as shown in Figure 2, the Integrated 2025 option significantly reduces the number of connections in those areas with the highest deployment of offshore wind. This is most noticeable in the east of England and north and east of Scotland, reducing clusters of radial connections down to a few, coordinated connections.

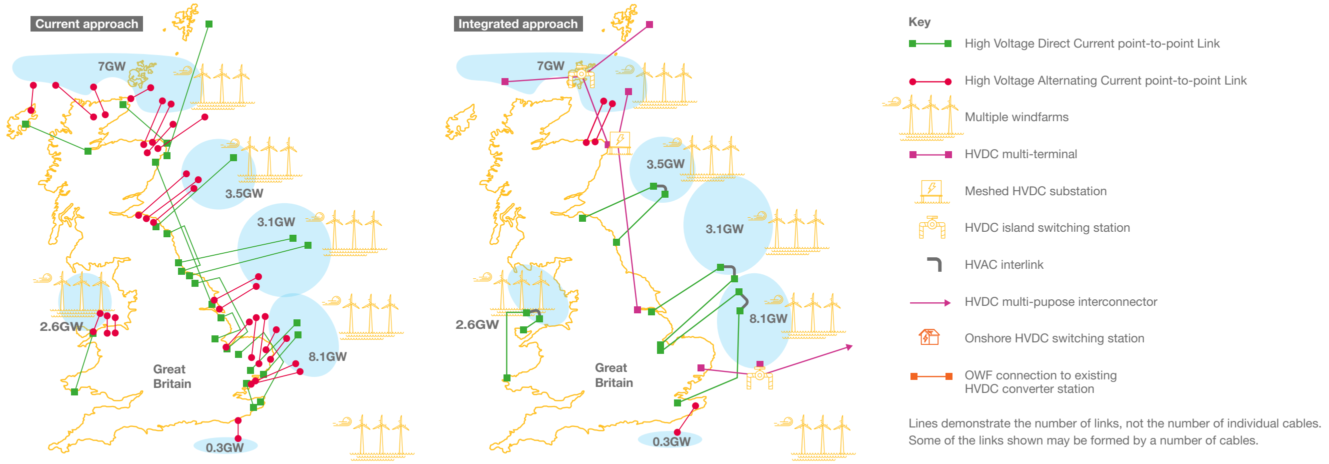

Figure 2 Status quo and Integrated Great Britain network designs in 2030

Please note, for Figure 2 and Figure 3:

- Under all options there will be significant levels of electricity to transport to where there is demand and an ongoing need to enhance the capacity of the onshore network. The designs assume that all of the transmission system reinforcements recommended to proceed in the 2020 *Network Options Assessment* (NOA) are built. They therefore do not appear in the designs. Details of the onshore network reinforcement assumed to be in place in addition to that set out in the network designs can be found in the assumed network reinforcements annex (See page 44).
- New offshore wind and interconnector projects that are due to connect to the onshore network prior to 2025 are assumed to have been built as planned so are not included in the designs. The same approach is taken for offshore infrastructure.
- Individual lines represent indicative cable corridors, which where relevant will include several cables, rather than single cables. Multiple cables landing in a single location will require larger onshore infrastructure than individual cables and will take up a greater area of seabed. The lines should also not be taken to be specific cable routes.
- These are conceptual network designs and further detailed analysis of many factors such as more detailed planning, coordination between the offshore and onshore networks and operational analysis are required to turn these into specific plans to take forward. Consideration of further *Future Energy Scenarios*, least worst regret analysis on the approach to take, seabed analysis and the impact on the environment and coastal communities is also needed. We are proposing progressing much of this in Phase 2.

Click to jump to enlarged diagram

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Summary of findings

2050: High-level comparison of the Integrated 2025 and 2030 network options to the status quo

By 2050, as shown in Figure 3, the integration of wind connections into new multi-purpose interconnectors, together with integration into existing interconnectors, is considered within these integrated designs. This further reduces the number of connections.

Different network designs are required for the Integrated 2025 and 2030 options, both onshore and offshore, as set out in Figure 3. As can be seen in designs, the extent of integration is reduced with the later start date, meaning a greater number of connections are required overall. This also reads through to a requirement for more onshore reinforcement in the Integrated 2030 option in order to support network boundaries capabilities and to reduce network constraints. Whilst this additional onshore reinforcement is higher than the Integrated 2025 option, it is a reduction from the status quo.

Also, to achieve the benefits in the Integrated design with the start in 2030, several new onshore reinforcements are required in order to support network boundaries capabilities and to reduce network constraints.

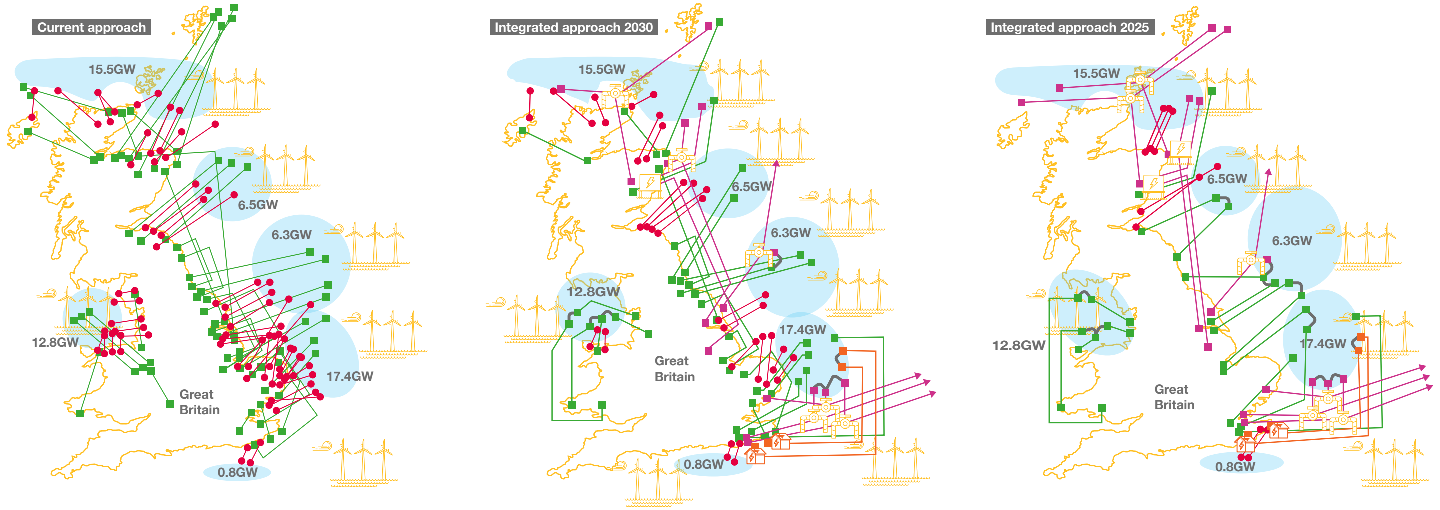

Figure 3 Status quo and Integrated Great Britain network designs in 2050

Click to jump to enlarged diagram

Summary of findings

Technology barriers and system risks to achieving the integrated option

In order to progress towards an integrated solution in the required timescales, our work has highlighted the following key barriers and risks that there would be benefit from being overcome. Apart from the highlighted change to the Grid Code, an integrated approach could be implemented without progress on any of these recommendations. However, greater benefits to consumers, the environment and coastal communities would result if these developments are taken forward. These can be divided into technology availability and system risks.

Technology Availability

The majority of the technology required for the Integrated option is available now or will be by 2030. However:

1. There is benefit from HVDC circuit breakers (DCCBs) progressing to commercial use in Europe. DCCBs have been used in three projects in China but not at transmission levels in Europe. Almost all the HVDC systems in operation today have been developed as point-to-point systems without the use of circuit breakers. Both Integrated options utilise DCCBs in Scotland, which we consider the optimal approach for transporting electricity further south. However, an integrated design can be developed in alternative ways if DCCBs are not available. If this was the case there would be additional network infrastructure required, coming at an additional cost. This would also have the potential to increase the likelihood of network faults and therefore impact on system reliability and operability.
2. Higher capacity HVDC submarine and underground cables need to be brought to wider commercial use in Europe to enable the power transmission from offshore to onshore at the capacities envisaged in the Integrated options if the change to the SQSS standard highlighted below is made. The proposed Integrated options assume that individual cables with capacities of 1.8 GW are available by 2040. Two such cables together in a bi-pole arrangement will allow connections of 3.6 GW. Currently, the highest individual HVDC cable capacity that is widely available is 1.4 GW, with higher capacities limited in supply options.

A targeted innovation strategy and support for early commercial use, for example through pilot projects where manufacturers can robustly test and iteratively improve their products, could help support the progression of both technologies. This recommendation was supported by a number of stakeholders in response to our consultation. There would also be benefit from the initiation of a coordinated process between energy companies, equipment manufacturers and standards organisations to consider options for the standardisation of offshore network designs, the development of functional specifications for technology currently available and to encourage the deployment of DCCBs to European standards in line with the required timing for offshore development timeframes.

Our assessment is that there are no other material HVAC or HVDC critical technology or asset dependencies that would impact development of an offshore integrated network.

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Impact of System risk on Offshore Integration

In order to deliver the benefit of the Integrated options we have identified that some changes are required to technical network codes and standards. Work to understand these changes and their impact should commence immediately to reduce the likelihood of missed opportunities.

Grid code

A review of the Grid Code[2] to clarify rules in relation to integrated HVDC-connected offshore windfarms will be essential. The rules for wind generation units set out in the existing Grid Code do not fully account for the characteristics of offshore wind farms connected to integrated HVDC offshore transmission networks through meshed connections.

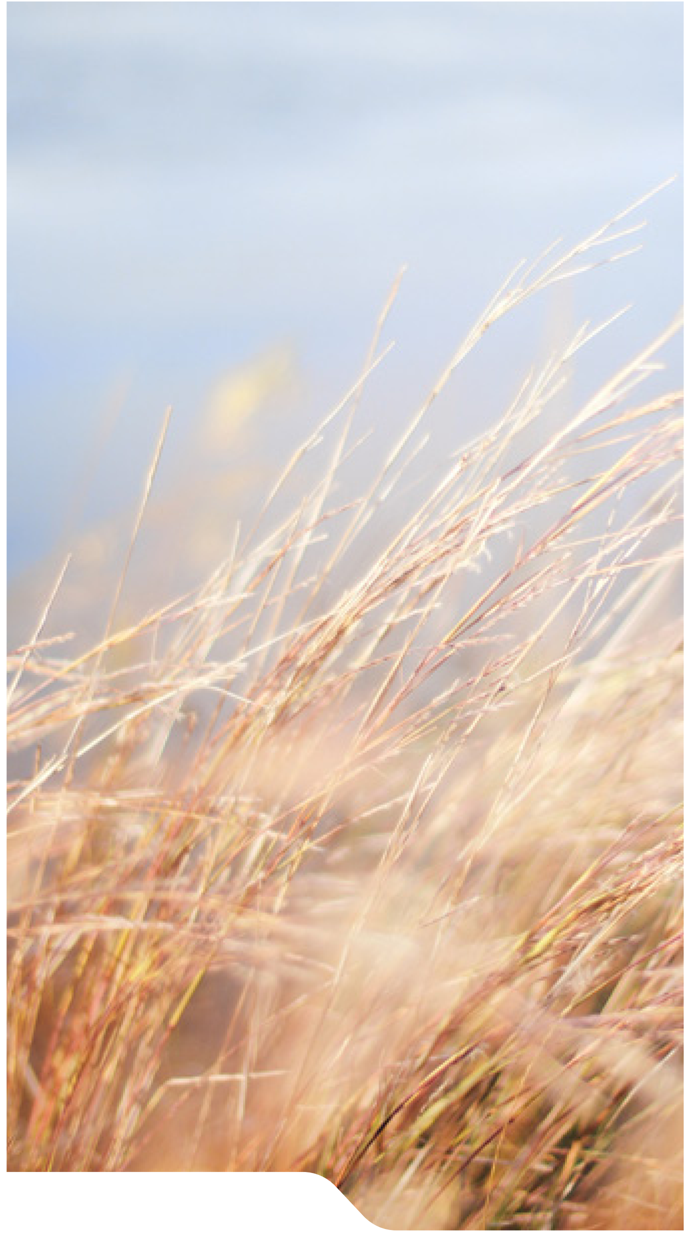
A review of the existing Grid Code, considering a number of technical and commercial challenges for meshed HVDC connections, would ensure rules are clear for offshore wind farms connecting in that way. We are proposing progressing this activity in our Phase 2 work.

Security and Quality of Supply Standard (SQSS)

An assessment of the costs and benefits of better aligning the limits for offshore networks in the SQSS[3] with the onshore network would potentially allow further integration, if the costs do not outweigh the benefits.

The current SQSS effectively limits offshore connections to 1.32 GW normal loss of power infeed risk. Some onshore generation and network assets have a higher, 1.8 GW limit, as infrequent infeed loss. A review of the SQSS would investigate the costs and benefits for better alignment of the limits that apply to onshore and offshore networks. If changes to the infeed loss are progressed, there will be corresponding operational changes and costs associated with the requirement for an increased reserve holding.

It is also likely further changes to the SQSS will be required for an integrated offshore network and these should be assessed and progressed as well. We are proposing progressing this activity in our Phase 2 work.



2 www.nationalgrideso.com/industry-information/codes/grid-code
3 www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards

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Analysing the impact of offshore integrated designs on the onshore system

We have completed high-level power system analysis of the three offshore connection approaches to determine their impact on the power flow distribution across the onshore transmission network, using the six regions set out in Figure 2.

These simulations provide a high-level indication of how the alternate offshore network designs impact the power transfers across onshore boundaries, and it allows the identification of areas where network reinforcements might be required. This is significant as boundary capacity is one of the main factors that influences the operation of Great Britain's onshore system and the planning needs for the future.

The power system analysis focused on flows of electricity around the network at a high level. Further analysis would be required to assess the impacts on system stability and dynamic performance. We propose carrying out this analysis in our second phase of work.

The key conclusions from the power system analysis were that the growth of installed offshore wind capacity and demand forecast between 2025 and 2050 will lead to more power flowing through the onshore network, including the boundaries used for network planning. This means there will be a requirement for additional onshore reinforcement across all options. The current onshore developments that are progressing through the planning and consenting process and more are required and assumed to be built in all of the options we considered. That includes and goes beyond the reinforcements recommended in the 2020 *Network Options Assessment*. However the Integrated options both have reduced levels of power flowing through the onshore network compared to the status quo. This is, 15 to 20 per cent less in the Integrated 2025 option in 2030 due to more of the power being transported to demand centres via the offshore network.

This rises to between 35 and 60 per cent in 2050 for both Integrated options, dependent on the region. This difference is reflected in the larger number of network constraints in the status quo option, requiring extensive reinforcements to the onshore network to allow normal operational conditions, thereby incurring higher investment costs than in the Integrated options. These higher onshore network investment costs are reflected in the Cost-Benefit Analysis.

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Cost-Benefit Analysis

Stakeholder feedback

The valuable feedback we received through our consultation this October has helped to shape our final Cost-Benefit Analysis Report, and the majority of feedback received supported the approach taken.

> **We would welcome greater clarity on the breakdown of cost savings and asset reduction driven by offshore integration, as both onshore and offshore assets are referenced in the report.**
>
> *- Transmission Owner*

We have made a number of specific changes to the Cost-Benefit Analysis Report following your feedback:

- A new section has now been produced on the footprint size of landing points between the status quo and integrated designs; the results of which are included within this summary.
- A more detailed explanation of the cost optimisation approach for the integrated approach has been included with the capex section of the full Cost-Benefit Analysis Report.
- A split of the capex costs between the offshore and onshore elements has been included within the capex section and a brief overview is included within this document. We have presented the information to enable a comparison between the status quo and Integrated options, and it is also possible to see the shift in asset type (onshore, offshore) on a year by year basis.
- Appropriate caveats have been added to the Cost-Benefit Analysis Report acknowledging the continued impact even in the integrated approach of impact to local communities and the local environment.

It is worth noting that not all of the changes we have made are covered within this summary due to the detailed nature of some of them (for example the treatment of array cables). The detail on the array cables and other detailed changes are covered fully in the main Cost-Benefit Analysis Report.

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Stakeholder feedback

There are a number of areas that we took the decision not to include in the Cost-Benefit Analysis Report. We can see the potential value they would provide in further enhancing the Cost-Benefit Analysis Report but have balanced that with the benefit of publishing this final report now in order to inform wider actions in the OTNR as soon as possible. These include:

- An assessment of the potential impacts on local communities and supply chains as a result of offshore coordination.
- An assessment of the likely range of the risk of under-utilisation (as experienced in other countries) if assets do not connect as anticipated.
- Analysis of the direct project costs that are associated with the onshore works of offshore connections, for example consenting activity or remedial works.
- A sensitivity analysis considering alternative generation profiles and types (in addition to the Leading the Way scenario currently considered).

Some of the feedback and suggestions we received covered topics that sit outside of the scope of our role as ESO. We have shared this feedback with the relevant organisations in the OTNR, of which this report forms part. This feedback included a range of suggested regulatory changes, approaches on the potential delivery models and requests for information of our works impact on specific connections.

> **The ESO states that the number of onshore and offshore assets, cables and onshore landing points could be reduced by ~50%, and states however that some of these assets would be somewhat larger. Is this therefore a benefit?**
>
> *- Transmission Owner*

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Approach to the Cost-Benefit Analysis

The Cost-Benefit Analysis assesses the three offshore network options against the key performance indicators (KPIs) set out on the following pages. The first option, referred to as the status quo, assumes that nothing changes in approach between today and 2050 in regard to planning or processes. The second option, referred to as the Integrated 2025 option, assumes that works offshore are coordinated from 2025, and shared assets bring the energy onshore where appropriate. The third option, referred to as the Integrated 2030 option, takes a similar approach to the Integrated 2025 option but with integration commencing from 2030. All three options assume that there are developments in the availability of technology such as larger HVDC converters and cables.

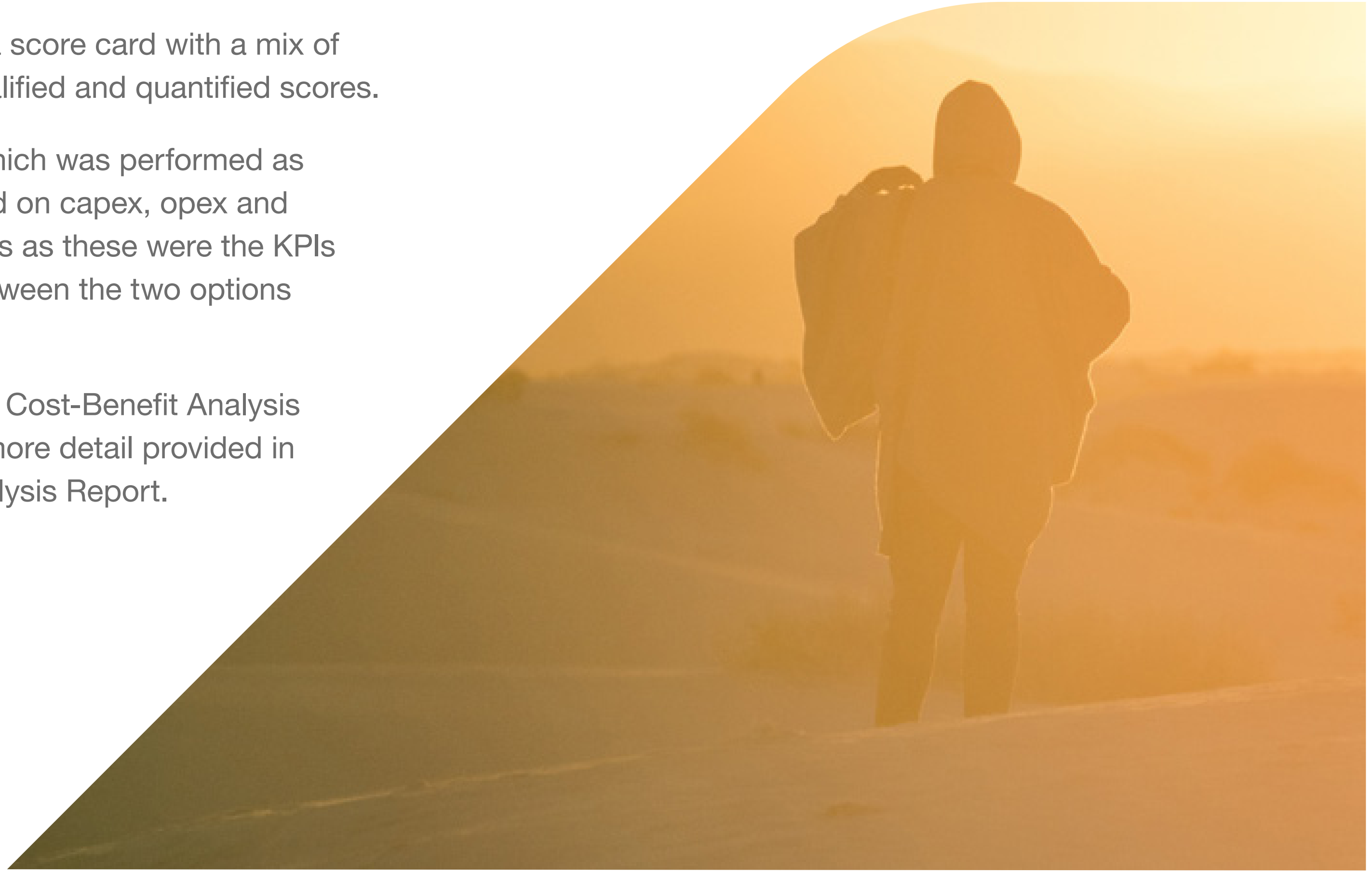
The Cost-Benefit Analysis scores the ten KPIs summarised in this section in three different ways, depending on the types of data being measured:

1. Monetised elements, which include the capital expenditure (capex) and operating expenditure (opex) costs of different types of transmission assets;
2. Quantified elements, such as carbon intensity variation between options; and
3. Qualified elements, which include considerations such as the impact on local communities from a social and environmental perspective.

This hybrid approach results in a score card with a mix of monetised comparators and qualified and quantified scores.

In the Integrated 2030 option, which was performed as a sensitivity analysis, we focused on capex, opex and environmental and social impacts as these were the KPIs with the greatest differences between the two options initially assessed.

A summary of the outputs of the Cost-Benefit Analysis are set out in this section, with more detail provided in the supporting Cost-Benefit Analysis Report.



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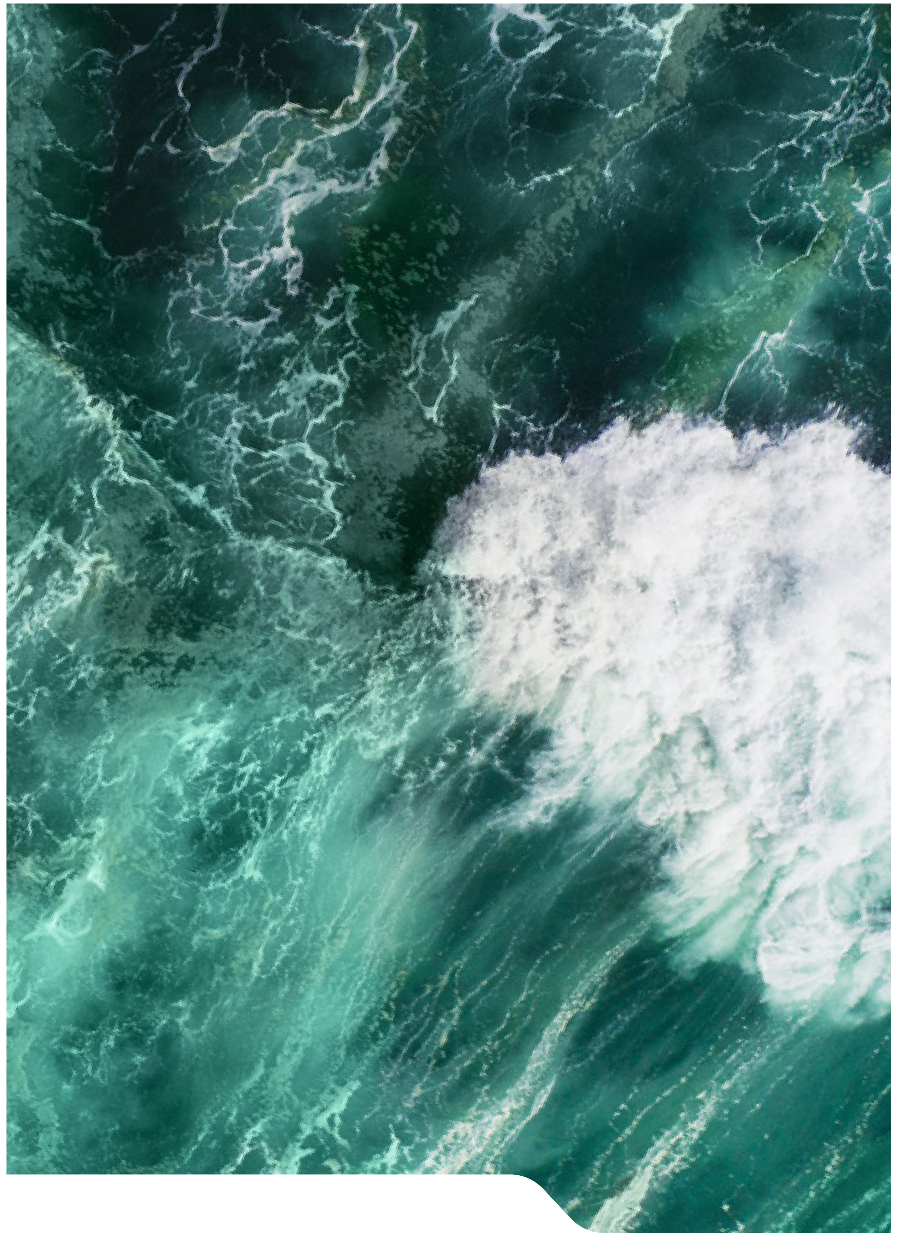
Overview

Overall, there is a greater benefit from the Integrated options across the criteria assessed. This is specifically in the Social/Local Impacts, Environmental Impacts, Capital Expenditure (capex) costs and Operating Expenditure (opex) costs.

There are potentially significant capital cost benefits to the Integrated 2025 option compared to the status quo option - up to £5.5 billion out to 2050 (19 per cent reduction) - and an up to a £1 billion reduction (14 per cent) in operational costs[4]. The extent of these cost savings varies across the different regions considered. The Integrated 2025 option also has the potential to significantly mitigate the environmental impact both offshore and onshore and also reduce the impact on the local communities as a result of a reduction in onshore and offshore infrastructure and number of landing points. Taking account of the assumptions made in our analysis, we estimate this could be around a 50 per cent reduction in total assets required for the Integrated 2025 option compared to the status quo. The current onshore developments that are progressing through the planning and consenting process and more are required and assumed to be built in all of the options we considered.

The Integrated 2030 option indicates that if integration commences in 2030, the benefits are roughly halved compared to starting integration in 2025. However, there is greater benefit in taking an integrated approach from 2030 than the status quo. Our sensitivity analysis suggests that if integration commences in 2030, there remains the potential for £3 billion, or 8 per cent, lower costs than the status quo by 2050 and 30 per cent fewer landing points and assets.

The potential for additional benefits in the 2025 to 2030 period demonstrates the need to deliver changes as soon as possible while continuing to meet the targets for 40 GW of offshore wind by 2030. Delivering the extent of integration required in this timescale would be extremely challenging and potentially risk meeting the target of 40 GW of wind by 2030. There is therefore a need to deploy innovative and flexible approaches to the connection of offshore wind in the intervening period until a new enduring, integrated, approach is in place. This would be with the aim that, as much as possible, the benefits of an integrated approach can be captured for consumers and communities without placing the delivery of projects underway and the offshore wind target at undue risk.



4 Please note we have added the capital and operating expenditure together and rounded down to £6 billion in the key messages. This £6 billion is roughly 18 per cent of total costs.

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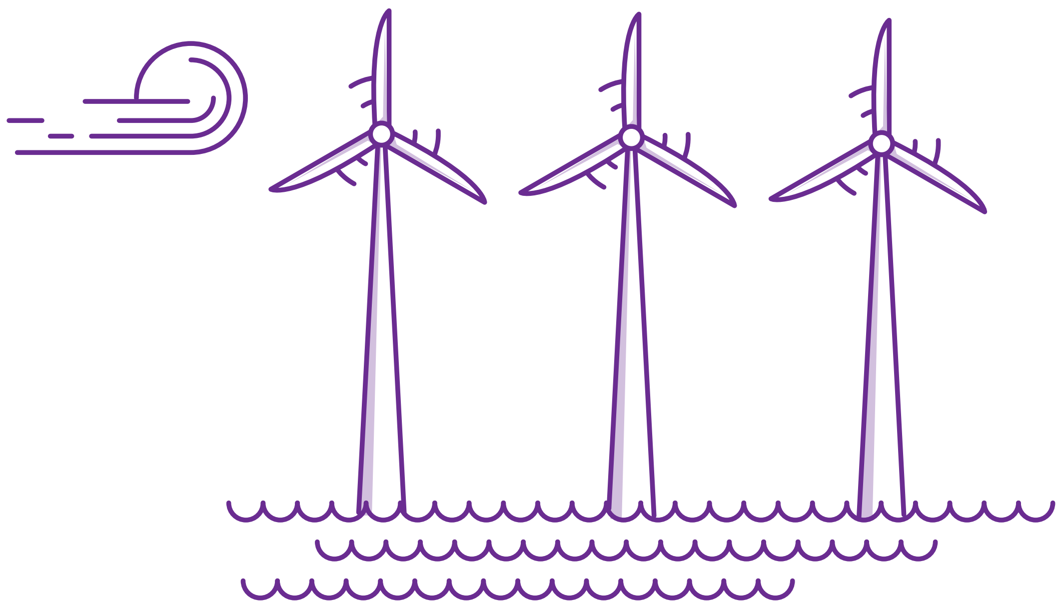
The integrated designs also have potentially more options for the location of the landing points due to the use of larger HVDC connections, allowing greater potential for them to be located in less environmentally and socially sensitive areas. However, the associated landing site infrastructure for HVDC technology is likely to be larger than for individual, radial connections and greater cable lengths will of course come at additional cost.

Whilst the Integrated and status quo options are compliant with the SQSS there are potentially additional benefits to the Integrated options. These include reducing the impact of network faults by offering power an alternative route to market in the event of partial network failure, potentially avoiding consequential boundary reinforcements and the ability to actively re-distribute power across Great Britain thus lessening the operational impact of outages and improving voltage management.

For some of the considerations assessed there is not a significant difference between the options. For example, the overall carbon intensity of the Great Britain generation fleet and the curtailment of renewable energy are very similar for the status quo and Integrated options out to 2050.



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Capital expenditure (capex)

Capex includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, land, preparatory work, designing, dismantling, equipment purchases and installation. The capex costs are based on discounted 2020 prices.

The capital costs of the Integrated 2025 option have the potential to be £5.5 billion, or 19 per cent, lower than the status quo option, based on the assumptions used. There are differences in costs between the six regions considered, which are driven by the technology choices, the volume of wind that is connected, and the onshore network capabilities.

If integration commences in 2030, there is the potential for over £2 billion, or 8 per cent, lower capex costs than the status quo by 2050. The costs of the three different options are set out in Table 2.

Where there is a large volume of wind generation to be connected to areas of the onshore system that are already approaching operational limits, or when offshore windfarms are located at larger distances, the Integrated options deliver greater benefits in terms of reduced capex. This is applicable to the Eastern Region, East Scotland and North Scotland.

In some regions where the distances are shorter and/or where the volumes of wind are low, the benefit is marginal between the two designs, for example in the North Wales & Irish Sea region. As the volume and distance of offshore connections increases, the integrated option becomes increasingly cost effective. The regions in which the benefits are highest are also those with the fastest earlier deployment. There is therefore benefit from moving to an integrated approach as soon as possible.

The largest differences in costs between the Integrated 2025 and Integrated 2030 options are seen in the Eastern Region, Dogger Bank and North Scotland. This is due to the high levels of capex spend in these regions between 2025 and 2030, meaning a significant proportion of the potential reduction in capex as a result of Integration is within this time period.

The comparative capital costs are set out in Table 2 below with the percentage difference being the cost of the Integrated 2025 and Integrated 2030 options compared to the status quo.

Region	Status quo capex, £m	Intergrated 2025 capex, £m	Percentage difference against status quo	Integrated 2030 capex, £m	Percentage difference against status quo
Dogger Bank	£6,064	£5,355	12%	£5,675	7%
Eastern Regions	£7,521	£5,263	30%	£7,016	7%
East Scotland	£3,709	£2,623	29%	£3,077	17%
North Scotland	£7,859	£6,382	19%	£7,241	8%
North Wales & the Irish Sea	£3,720	£3,650	2%	£3,663	2%
South East	£126	£126	0%	£126	0%
Total Capex	£29,000	£23,339	19%	£26,798	8%

Table 2 Capital costs of the three network designs across the six regions assessed, £ million discounted to 2020 prices

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In response to feedback we are providing more granular information on the location of the cost savings in relation to the status quo and Integrated 2025 option. The majority of cost savings in the Integrated approaches are onshore, with some relative cost increases offshore. This is due to relatively more infrastructure being built offshore in the Integrated designs in order to transport electricity closer to where it is needed and reduce the build onshore. This reduction does not include the onshore developments that are progressing through the planning and consenting process that are required and assumed to be built in all of the options we considered. These and further reinforcement works set out in the 2020 *Network Options Assessment* are already included in the Integrated design and will still need to be undertaken by the TOs, regardless of in the approach taken to connecting offshore generation.

We have presented capex savings as onshore and offshore costs. It should be noted that these costs are split on a geographical basis, and not driven by whether assets are owned by Offshore Transmission Owners (OFTOs) or onshore TOs.

Please note that these overall capital costs differ from other recently published reports as they cover different elements of offshore wind. For example, other analysis such as that by Aurora[5] and the National Infrastructure Commission[6] assess the total costs of projects and Contract for Difference returns needed. They therefore include the costs of elements such as the wind turbines that go above the network considerations we have assessed and are relevant to this project.

Onshore capex £ million	Status Quo	Intergrated 2025	Difference against status quo	Integrated 2030	Difference against status quo
Dogger Bank	£ 2,031	£ 660	68%	£1151	43%
Eastern Regions	£ 2,668	£ 497	81%	£1220	54%
East Scotland	£ 1,041	£ 375	64%	£554	47%
North Scotland	£ 2,987	£ 2,534	15%	£3170	-6%
North Wales & the Irish Sea	£ 1,618	£ 492	70%	£482	70%
South East	£ 26	£ 26	0%	£26	0%

Offshore capex £ million	Status Quo	Intergrated 2025	Difference against status quo	Integrated 2030	Difference against status quo
Dogger Bank	£ 4,033	£ 4,695	-16%	£4523	-12%
Eastern Regions	£ 4,852	£ 4,766	2%	£5796	-19%
East Scotland	£ 2,668	£ 2,248	16%	£2523	5%
North Scotland	£ 4,872	£ 3,848	21%	£4071	16%
North Wales & the Irish Sea	£ 2,103	£ 3,158	-50%	£3181	-51%
South East	£ 100	£ 100	0%	£100	0%
TOTAL	£ 29,000	£ 23,399	19% (£5,600)	£26,798	8%

Table 3 Onshore and Offshore Capex in status quo, integrated 2025 and 2030

5 www.auroraer.com/insight/reaching-40gw-offshore-wind
6 nic.org.uk/studies-reports/renewables-recovery-and-reaching-net-zero/

Operating expenditure (opex)

Opex is based on the projects' operational and maintenance costs. The opex figures are based on discounted 2020 prices.

Our analysis suggests that between 2025 and 2050 opex costs are £1 billion or 14 per cent lower in the Integrated 2025 option and £700,000 or 10 per cent lower in the Integrated 2030 option. This is shown in Table 4 which sets out the difference in cost savings of both Integrated approaches, compared to the status quo. In addition to the information presented on capex in the previous section, this covers opex and total costs.

The reduction in opex costs for the Integrated 2025 option is not as significant as for capex as the it uses more HVDC components, which generally have higher operating costs than HVAC equipment. This higher cost on a unit basis is outweighed in the overall picture by the significant reduction in the number of assets required in the Integrated 2025 option compared to the status quo. The Integrated 2030 option sits in between the two options in terms of opex savings, reflecting the relative mix of HVDC and HVAC assets and the relative number of them. The profile of opex spend is set out in Figure 4.

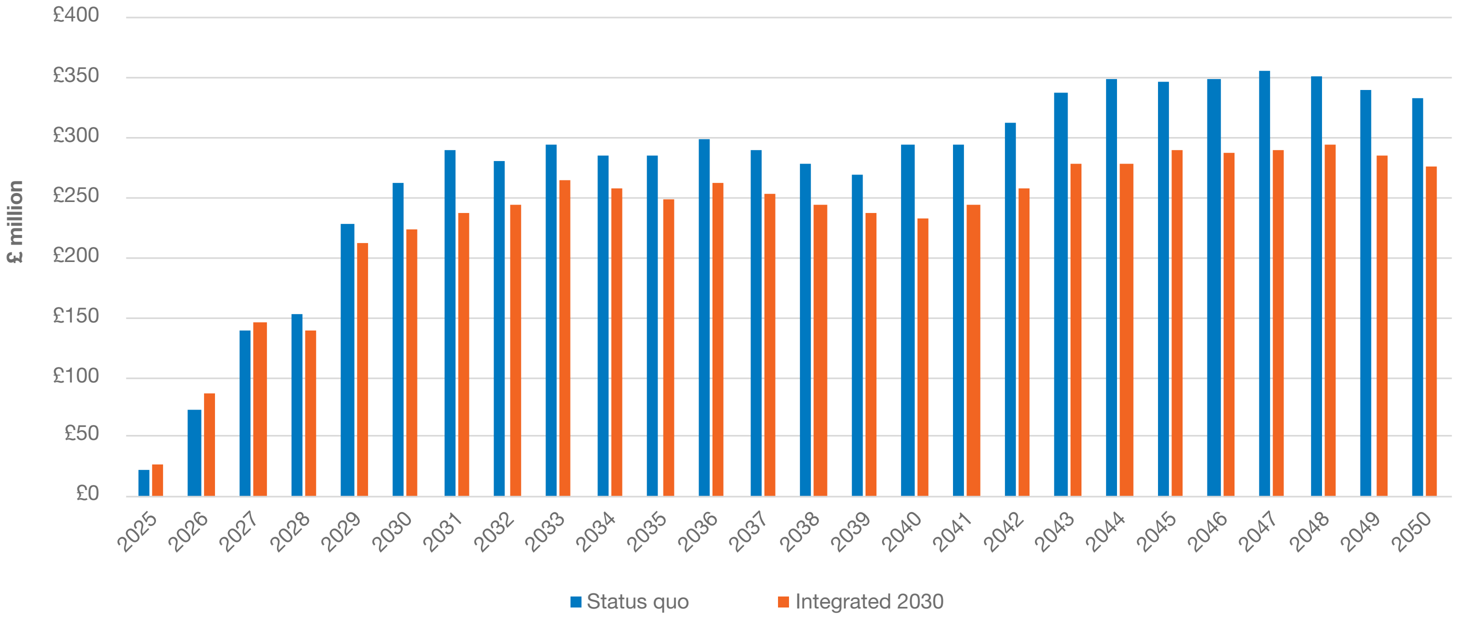

Figure 4 Operational costs of the two network designs across all of Great Britain, in £ million discounted to 2020 prices

	Status Quo	Intergrated 2025	Benefit compared to status quo	Integrated 2030	Benefit compared to status quo
Capex	£29,000	£23,399	19%	£26,798	8%
Opex	£7,113	£6,097	14%	£6,429	10%
Total	£36,112	£29,946	18%	£33,327	8%

Table 4 Lifetime comparison of the discounted costs (discounted to 2020 prices) of the Status Quo, Integrated 2030 and Integrated designs (values in £ million)

Summary of findings

System Costs

The System Costs are those costs directly incurred by the generator in the production of energy and by the ESO in managing the system. These are ultimately passed onto consumers.

Our analysis indicates that by 2050 there is only a marginal difference between the Integrated 2025 and status quo options. For both options the constraint costs are less than half a per cent of the total generation costs.

Renewable Energy Integration

This KPI assesses the impact of the two options on the generation volumes of existing renewable power plants, unlocking existing and future renewable generation, and minimising curtailment of electricity produced from renewable sources.

Similar levels of renewable energy generation are facilitated in the two options assessed (status quo and Integrated 2025); the volumes are set out in Table 5. The difference increases slightly over the years, although it remains small.

	Renewable Generation TWh			Renewable Generation Capacity Curtailed TWh		
	2030	2040	2050	2030	2040	2050
Status quo	290	417	561	65	65	88
Integrated 2025	289	418	552	67	64	96

Table 5 Estimated renewable generation in assessed years, in TWh per year

Carbon intensity variation

The carbon intensity variation is the change in carbon dioxide (CO_2) emissions in the power system influenced by the two options assessed. This is a consequence of differences in the dispatch of generation and unlocking renewable energy potential. All figures are shown in million tonnes of CO_2 (Mtonnes) per year.

The carbon intensity of the two options assessed is very similar out to 2050, which is set out in Table 6. The difference is not material, with slightly higher emissions in the Integrated 2025 option than in the status quo.

Grid losses

This KPI reflects the annual onshore grid losses, accounting for the losses incurred in the onshore transmission system.

As can be seen from Table 7, the total annual Grid Losses as a percentage vary only marginally between the Integrated 2025 and status quo options in our analysis. Additionally, the percentage of total generation lost also does not increase overtime in our analysis.

Taken together our analysis indicates that total annual Grid Losses are not a relevant factor by which to choose an option and neither are they likely to be an increasing challenge as the capacity of offshore wind increases on the Great Britain network.

	2030	2040	2050
Status quo	16.7	6.9	2.6
Integrated 2025	16.7	6.8	2.6

Table 6 Variation of carbon intensity of the Great Britain generating fleet (Mtonnes)

	2030	2040	2050
Status quo	2.2%	2.0%	2.1%
Integrated 2025	2.0%	1.9%	2.7%

Table 7 Total annual Grid Losses as a percentage of Total Generation

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Security of supply – Adequacy, Stability and Resilience

Security of supply split into three components:

- Adequacy assesses each option's ability to satisfy the consumer demand and the system's operational constraints at any time, in the presence of scheduled and unscheduled outages of generation and transmission components or facilities.
- Security is defined as each option's ability to withstand disturbances arising from faults and the unscheduled removal of equipment without further loss of facilities or cascading failures.
- Resilience is an assessment of the power system's ability to withstand faults and recover after a fault has occurred.

For all of the Security of Supply KPIs mentioned above, our analysis indicates that both options assessed (status quo and Integrated 2025) are compliant with the relevant industry codes and requirements.

Whilst both options are compliant, there are a number of areas where the Integrated 2025 option provides benefits over and above the status quo option. These include:

- Reducing the impact of network faults by offering power an alternative route to market in the event of partial network failure;
- Avoiding consequential boundary reinforcements, which otherwise are needed in the status quo option; and
- Reductions in the operational impact of outages and improving the voltage management (e.g. the ability to generate power flow to suppress high volts), and other support services (e.g. dynamic system support) as a result of the ability to actively re-distribute power across Great Britain.

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Environmental

Based on the assessment of the scale of assets required and the estimated number of landing points there is likely to be a significant reduction in the impact on the onshore and offshore environment and socially with the Integrated 2025 option. Benefit is still seen with the Integrated 2030 option compared to the status quo, although to a lesser extent than the Integrated 2025 option.

Feedback we received from environmental stakeholder groups highlighted the key sensitivities of habitats and marine protected areas in offshore waters and the need wherever possible to minimise the disruption of these.

On the basis of the assumptions used in the Holistic Approach to Offshore Transmission Planning Report to develop the conceptual network designs, the number of landing points for the Integrated 2025 option is estimated to be 30 by 2050, 60 for the Integrated 2030 option and 105 for the status quo.

Also taking into account the assumptions in the development of the conceptual network designs, the number of network assets in the Integrated 2025 option are 60 per cent lower in 2030, and around 70 per cent lower by 2050. In the Integrated 2030 option they are around 30 per cent lower by 2050. This relates to onshore substations, export cables and offshore platforms.

These figures are caveated in that they represent a snapshot of the designs and are illustrative of the difference between the three options for offshore network designs we considered. More detailed planning, coordination and operational analysis would be required to progress the conceptual designs to implementable network designs, which may change these figures.

An additional benefit of the Integrated solutions is that given their use of HVDC technology, which allows for greater lengths of sub-sea cable, there is greater flexibility on where landing points can be located and therefore offer greater potential to be located at less environmentally sensitive sites. Such flexibility would of course have to be weighed against the additional costs of additional cable lengths in any project assessment.

We have estimated the total land utilised by landing sites between the different options. The Integrated approach uses larger HVDC cables and the landing sites are larger than for the status quo. However, the significantly larger number of landing sites in the status quo approach means that the total area of land used across GB in the Integrated 2025 approach for landing sites is about 55 per cent less.

The difference between the Integrated 2030 option and the Status Quo is much closer, as set out in Table 8, with only a 20 per cent reduction in the total area of landing points. The reduction in the difference from the status quo is as a result of the high volumes of capex build in the 2025-30 period.

Table 8 provides a high level assessment of the total area of onshore substations that could be required to accommodate onshore transmission infrastructure for the three designs – Status Quo, Integrated 2025 and Integrated 2030.

Integrated 2025	Integrated 2030	Status quo
173	310	386

Table 8 Estimate of total landing points' area (in hectares)

Even with reductions in impact outlined there will be environmental impacts of the offshore and onshore grid development. Environmental stakeholders told us there may be an irreversible impact on environmentally 'sensitive' areas. Such impact could be from construction like damage to watercourses and habitats, pollution and noise, disruption to seabed and marine life but also to the migration patterns of fish and fowl and the loss of visual charm.

We suggest the impact is considered further in the more detailed network planning proposed in our next phase of work.

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Community and Social

Based on the assessment of the estimated number of assets and landing points required, there is likely to be a material reduction in the local, social impact with the Integrated options compared to the status quo.

To assess the social impact, we invited feedback on specific questions from a range of councils around Great Britain, targeting both those experiencing high levels of offshore development currently and those which are likely to see it in future. We received responses from councils in the east of England.

The east of England council officials supported offshore wind as an important part of the future Great Britain's energy system, as a means to reduce the effect of climate change and achieve net zero greenhouse gas emissions by 2050.

The respondents saw offshore wind as a possible economic catalyst for Great Britain as a whole, including on technology development, industry growth, higher employment and energy independence.

They believe that offshore wind has potential as an economic stimulus for their local area and community, including infrastructure development, uplift in property value, industry growth and higher employment. However, they feel that the benefits are for Great Britain more widely than for the local community.

The biggest impacts on a local community are seen to be:

- The disruption during the construction phase of the cable route (including construction of sub-stations and booster stations); the long-term impact associated with the permanent / semi-permanent, large structure/s (i.e. landscape and visual impact);
- Lack of coordination between infrastructure projects; and
- Inadequate mitigation and compensation for local communities.

The respondents recognised that it was not realistic to wholly avoid new connections in their areas when connecting offshore wind into the electricity transmission system. However, they believe that network connections should be more strategic and coordinated to minimise onshore impacts.

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Offshore Connections Review

Stakeholder feedback

The feedback we received through our consultation has informed our Offshore Connections Review Report. The major themes that emerged from this feedback included:

- Widespread support for the suggested changes with no significant additional elements or changes identified.
- Suggestions to change the present Connections and Infrastructure Options Note (CION) processes to include a greater level environmental assessment as part of our processes.
- Redrafting of the connections process to be more flexible for different types of connections, for example demand, generation, multi-purpose interconnectors.
- Some cautionary concerns regarding the suggestion of formalising the role of developers in code and that this should be progressed carefully as delivery and compliance risks are involved. These concerns will be reviewed and assessed as part of any code modification process under future work, through Workstream 4 of the second phase of the project.
- Some concerns about live connections and how these may be impacted by the work that we are undertaking, including impacts on consenting. We have committed to honour live connection agreements unless directed otherwise.

These suggested changes will be taken forward in two ways as part of Phase 2 of the project. Firstly, through a workstream for the immediate to short-term coordination of connections and changes to the CION process. Secondly, the medium- to longer- term suggestions will form part of the workstream progressing a roadmap or rollout plan for the industry changes required to facilitate the enduring offshore regime.

> **Reviewing and codifying the CION will provide clarity and certainty on the process and as such will be welcomed.**
>
> *- Offshore developer*

> **We believe the proposed areas of improvement should be flexible enough for maintaining the pace of existing project developments while progressing with changes in favour of a wider coordination.**
>
> *- Offshore developer*

Offshore Coordination Project / Summary of findings 36

Summary of findings

Key recommendations from the Offshore Connections Review Report

We recommend the following actions are taken forward to improve the connections process in the timescales set out below. Work is already underway to progress the immediate-to short-term opportunity.

The timeframes referred to in this section are:

Timeframe	Expected connection date
Immediate-term	early 2020s
Short-term	mid to late 2020s
Medium-term	mid to late 2020s & early 2030s
Long-term	early to mid-2030s & beyond

Table 9 Timeframes referred to in the Offshore Connections Review Report

Immediate to Short Term Opportunities

1. Review the CION to implement improvements that drive and encourage coordination

The CION process evaluates a range of transmission options to lead to the identification and development of the overall efficient, coordinated and economical connection point for offshore connections, onshore connection design and, where applicable, offshore transmission system / interconnector design to develop and maintain an efficient, coordinated and economical system of the electricity transmission network.

This review includes considering:

- The value of exercising the existing option to reopen the CION and encourage coordination of projects;
- The development of the concept of regional CIONs, where a group of connections in a similar geographical area are assessed through the CION process; and
- The mechanisms for how key stakeholders could be more involved in relevant points in the process.

This should allow us to facilitate coordination in a clear, transparent and defined way, allow easier access to connection sites for project developers, and enhance the capacity to connect more customers in the future.

This recommendation will help address some of the current issues with the CION that stakeholders have fed back, which include:

- The time taken to complete the CION process and a lack of consistency in the average times for offers;
- The level of communication and collaboration between the ESO, the project developer and key stakeholders such as local councils and environmental organisations;
- The current process is iterative and the outcome of one CION analysis must be known before another CION can be completed with any certainty;
- Generation background assumptions are not applied consistently across CION projects and changes are too frequent, which results in the process taking a long time, re-work taking place and unexpected changes for the connectee; and
- Coordination across projects is challenging as a result of the CION being a standalone project by project assessment rather than taking a coordinated approach with a multi-developer CION considering numerous projects at the same time.

In collaboration with the relevant stakeholders we will agree the timescales in which we can implement this option and will manage these improvements through Workstream 3 of Phase 2 of the project.

Offshore Coordination Project / Summary of findings 37

Summary of findings

Medium to Long Term Opportunities

These are our current proposals for medium to long-term opportunities, that we plan to deliver in our second phase of work. However, some may need to change dependent on the overall direction of travel set by the OTNR and how they fit within that. The assessment we carry out as part of our proposed roadmap changes may also suggest different activities or changes to these may be required.

1. Package or coordinate connection offers

In this activity, we will investigate in conjunction with The Crown Estate and Crown Estate Scotland whether it would be possible to package a connection offer with the seabed lease agreement to encourage greater coordination. This would focus connection applications on a specific time window as far as possible and would therefore also potentially facilitate the management of applications as a group. This activity will link into any relevant work in other parts of the OTNR too. This is likely to have a knock on effect on other processes such as the CION, the role and concept of which may need reviewing and a new approach developed if appropriate.

This would help address the issue that the connections process can be long with key milestones for progress often separated by multiple years. It will help with the timing of decision making and the availability of information throughout the process and help prioritise the projects with higher certainty of progressing. Considering connection applications together as part of the zone would also allow more coordination with interested parties onshore.

2. Review where the risk sits for financial liabilities for offshore connections and ensure that this is optimal for encouraging coordination

In an integrated approach, where multiple developers are connecting to an offshore network, there needs to be clear agreement on how the project liabilities will be managed and ensure that this is done in a way that balances the needs of projects to gain appropriate funding with ensuring that one party does not penalise another and also ensuring that incentives are in place to drive coordination. Project liabilities are the risks of costs that are incurred (generally by the TOs) between an application being accepted and the connection being completed and generation starting. This review may involve refinement of the current liabilities for broader system and generator-driven investment.

In addition, developers will need a clear route to market and certainty on delivery of their connection assets. Where this goes beyond the remit of the ESO we anticipate that this will be considered as part of the BEIS-led Offshore Transmission Review.

3. Consider formalising developers' roles in the System Operator-Transmission Owner Code (STC) to improve the efficiency and customer focus of the CION decision making process

This would enable developers to be formally involved in the CION process especially with the proposed grouped studies and help further with some of the challenges highlighted on the previous page.

This would also potentially give developers more direct control over the works that they are reliant on and therefore allow them and others up to coordinate more when the certainty is increased.

4. Codification of the CION into the Connection Use of System Code (CUSC)[7] to define timescales and provide clarity and consistency

Although not coordination-specific, this would be beneficial in streamlining offers and ensuring consistency for all connections. Codification of the CION would have the benefit of greater transparency for customers, with potentially greater certainty and more information earlier in the process.

For clarity, the scope of this proposed review would not merely be the translation of the present CION approach into a codified form, rather a full review of the process with the codification of any revised approach.

7 www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc

Offshore Coordination Project / Summary of findings 38

Summary of findings

Next steps for the recommendations

Immediate to short term opportunities

The opportunities outlined to change the present CION approach will be progressed by the workstream delivering immediate to short-term coordination opportunities, within Phase 2 of the Offshore Coordination Project.

Medium to long term opportunities

To progress the medium to long-term recommendations for connections that will improve the process for the enduring offshore regime, code changes may be required, for example to the STC and the CUSC as outlined in the previous section. This work will be captured as part of Phase 2 of the project where, with our stakeholders, we will scope, prioritise and progress the necessary changes to industry standards holistically. There may be additional changes to the connections regime proposed as part of this assessment. We have also set out these activities in an addendum to the RIIO-2 business plan[8] delivery schedule. More information can be found in the What happens next? section (See page 40).

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8 www.ofgem.gov.uk/system/files/docs/2020/12/final_determinations_technical_annexes_part_one.zip

What happens next?

The publication of this Phase 1 final report marks the conclusion of the first phase of work within our Offshore Coordination Project. Through this, we have laid the foundations for offshore coordination and established the potential significant economic, social and environmental benefits of this approach, particularly if action can be taken swiftly. Both we and our stakeholders believe work needs to continue at pace and in a coordinated way to realise the potential benefits, and take the work set out in Phase 1 from a vision to reality.

Under the OTNR and in line with the commitments in the Energy White Paper, we plan to progress Phase 2 of our project. This is with the objective of delivering the activities within the ESO's remit that are required to facilitate the implementation of a new, enduring offshore transmission network approach and steps to deliver coordination whilst that is implemented. The scope for this second phase of work has been shaped by feedback we received through our consultation, as well as by members of the OTNR and ESO Networks Stakeholder Group (ENSG), and we will continue to engage more broadly on the detail of work within each workstream as this second phase of work commences.

Stakeholders who responded to BEIS and Ofgem's open letter earlier this year noted that the ESO, BEIS and Ofgem should continue to work on offshore coordination jointly, remain closely aligned and avoid duplication or disconnect. We recognise the importance of this and will ensure this as we progress with Phase 2, which has been scoped to align with our current understanding of the OTNR workstreams.

Stakeholder feedback

As well as requests for specific additional work on the technical aspects and Cost-Benefit Analysis, stakeholders recommended we proceed immediately with necessary code changes and codifying the timescales for the CION process. There were recommendations to review how other countries are considering a systemwide approach to integrating offshore wind, and recurring questions on what an integrated network means for the charging regime. There was a view that pathfinder projects before 2030, enabled by a flexible approach to regulation from Ofgem and BEIS, will be essential to realising the most substantial benefits.

In response to this feedback, we intend to establish the required changes to industry codes and regimes, as well as explore international aspects of offshore coordination and how we can support pathfinder projects. We agree work needs to happen rapidly and will drive progress where this is within out remit, using the overarching direction from the OTNR.

Scope for Phase 2

Phase 2 intends to move Great Britain closer to an integrated offshore network, through four workstreams that have been shaped by consultation feedback and industry groups:

1. Develop long term ESO offshore coordination objectives in alignment with the OTNR
2. Recommend planning and regulatory framework changes, and set out an operational strategy
3. Identify and deliver tactical coordination opportunities for inflight connections, to support the transition between current state and an enduring integrated offshore regime (aligned to BEIS and Ofgem's pathfinders)
4. Publish and deliver an industry-agreed roadmap of code modifications, establishing the necessary changes to codes and frameworks to facilitate offshore integration

Offshore Coordination Project / What happens next? 40

What happens next?

Phase 2 **Workstream 1:**

Develop long term ESO offshore coordination objectives in alignment with OTNR

An overarching workstream to develop the long term ESO objectives for offshore coordination and work with BEIS and Ofgem to agree the role that could be valuable for the ESO to play in the enduring regime and potentially any interim approaches.

Phase 2 **Workstream 2:**

Recommend technical planning, network coordination and regulatory framework changes, and set out an operational strategy

Building on the technical analysis from Phase 1, this workstream encompasses:

- The development of more detailed offshore network designs based on agreed scenarios, including assessment of social, environmental and seabed impacts, more detailed assessment of the onshore network capacity for offshore connections, the costs and benefits of different network designs and least worst regret analysis to help manage uncertainty
- A review of the SQSS infeed loss for offshore assets
- The development of planning and operating standards for an integrated offshore network.

Phase 2 **Workstream 3:**

Identify and deliver early opportunities for coordination, to support the transition between the current state and enduring integrated offshore regime.

Aligning closely with the BEIS and Ofgem pathfinder projects, identify and recommend an approach for coordination opportunities with inflight connections. Once an approach has been agreed, support implementation.

Phase 2 **Workstream 4:**

Publish and deliver an industry-agreed roadmap, establishing the necessary changes to codes and frameworks to facilitate offshore integration

Create, engage on and publish a detailed, industry-agreed roadmap (roll-out plan) of changes required to industry codes and frameworks, including prioritised activities and timelines. This covers technical and commercial codes and standards, the charging regime and the connections regime (including actions identified in Phase 1 of the Offshore Connections Review Report). The work stream will initiate and drive the change set out in the roadmap, working closely with industry and Ofgem. A review of international developments and good practice for integrated offshore networks will also be carried out.

We welcome your views on this next phase of work and look forward to continuing to work with you as, together, we progress towards greater offshore coordination, helping to facilitate a zero-carbon future in a way that delivers economic benefits and minimises the impacts on coastal communities and the environment.

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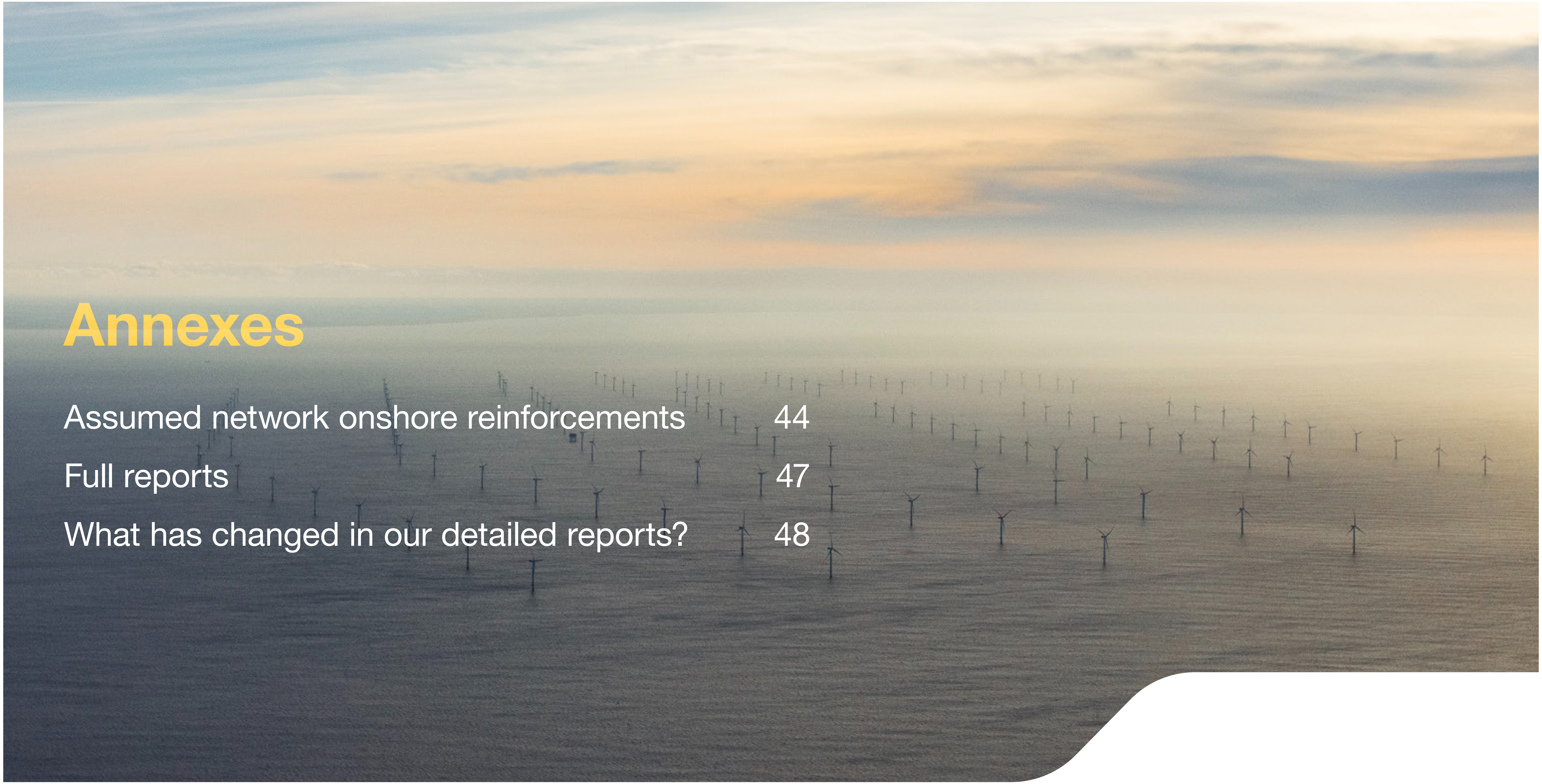
Continuing the conversation

Email us with your views on Offshore coordination or any of our future of energy documents at box.OffshoreCoord@nationalgridESO.com and one of our team member will get in touch.

For further information on the project and current and past events please visit: www.nationalgrideso.com/future-energy/projects/offshore-coordination-project

Write to us at:

Offshore Coordination Team
Faraday House
Warwick Technology Park
Gallows Hill Warwick
CV34 6DA



Annexes

Assumed network onshore reinforcements

The increased levels of offshore wind mean the current onshore developments that are progressing through the planning and consenting process are required and assumed to be built in the design of the offshore integrated solution.

We have used those investments as a basis in our network model, making sure that we are maximising the use of the proposed infrastructure. However, going forward the *Network Options Assessment* process each year will recommend which of those delayed/on hold reinforcements should proceed at that particular point in time.

The annual NOA is a key ESO deliverable. It describes the major projects that we are considering to meet the future needs of Great Britain's electricity transmission system that the *Electricity Ten Year Statement*[1] (ETYS) outlines and recommends investments in the year ahead.

Last year's NOA assessed 147 projects and recommended that 42 proceed as part of ensuring value for GB consumers. Those 42 options would represent a total investment of over £11 billion of which £200 million would be invested in 2020/21. We are still progressing this year's NOA analysis, with final results due to be published in January 2021. We anticipate a similar or greater level of investment to be recommended from this year's analysis as we look to meet the net zero targets described in the 2020 *Future Energy Scenarios*. NOA 2020/21 will also consider additional sensitivities evaluating the economic benefit offshore wider works may provide to consumers, more information on this will be published in January 2021.

NOA 2020 investments taken into consideration in our analysis

Option code	Option description	EISD
South West		
BNRC	Bolney and Ninfield additional reactive series compensation	2023
FLR3	Reconductor Fleet to Lovedean circuit	2020
MBHW	Bramley to Melksham circuits thermal uprating	2023
SEEU	Reactive series compensation protective switching scheme	2022
BFHW	Bramley to Fleet circuits thermal uprating	2022
BFRE	Bramley to Fleet reconductoring	2024
HBUP	Uprate Bridgewater to 400 kV and reconductor the route to Hinkley	2024
MBRE	Bramley to Melksham reconductoring	2024
THRE	Reconductor Hinkley Point to Taunton double circuit	2024
South East		
BMM2	225 MVAr MSCs at Burwell Main	2022
BPRE	Reconductor the newly formed second Bramford to Braintree to Rayleigh Main circuit	2029

Option code	Option description	EISD
BRRE	Reconductor remainder of Bramford to Braintree to Rayleigh route	2024
BTNO	A new 400 kV double circuit between Bramford and Twinstead	2028
CS51	Commercial solution for East Anglia	2024
CS53	Commercial solution for the south coast	2023
GRRA	Grain running arrangement change	2020
KLRE	Kemsley to Littlebrook circuits uprating	2020
NTP1	Power control device along North Tilbury	2023
RTRE	Reconductor remainder of Rayleigh to Tilbury circuit	2021
SCD1	New offshore HVDC link between Suffolk and Kent Option 1	2028
SER1	Elstree to Sundon reconductoring	2023
TKRE	Tilbury to Grain and Tilbury to Kingsnorth upgrade	2026
CTRE	Reconductor remainder of Coryton South to Tilbury circuit	2021
EAM1	225 MVAr MSC at Eaton Socon	2023
EAM2	225 MVAr MSC at Eaton Socon	2023

1 www.nationalgrideso.com/research-publications/electricity-ten-year-statement-etys

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Assumed network onshore reinforcements

NOA 2020 investments taken into consideration in our analysis

Option code	Option description	EISD
ESC1	Second Elstree to St John's Wood 400 kV circuit	2024
GKEU	Thermal upgrade for Grain and Kingsnorth 400 kV substation	2022
NBRE	Reconductor Bramford to Norwich double circuit	2024
NEC1	Cable replacement at Necton 400 kV substation	2024
NOM1	225 MVAr MSC at Norwich	2023
NOM2	225 MVAr MSC at Norwich	2023
PEM1	225 MVAr MSC at Pelham	2023
PEM2	225 MVAr MSC at Pelham	2023
RHM1	225 MVAr MSC at Rye House	2023
RHM2	225 MVAr MSC at Rye House	2023
SCD2	New offshore HVDC link between Suffolk and Kent Option 2	2029
SER2	Elstree to Sundon 2 circuit turn-in and reconductoring	2023
WAM1	225 MVAr MSC at Walpole	2023
WAM2	225 MVAr MSC at Walpole	2023
WAM3	225 MVAr MSC at Walpole	2023
WYTI	Wymondley turn-in	2022

Option code	Option description	EISD
Midlands		
CGNC	A new 400 kV double circuit between Creyke Beck and the South Humber	2031
CTP2	Alternative power control device along Creyke Beck to Thornton	2024
GWNC	A new 400 kV double circuit between South Humber and South Lincolnshire	2031
MRPC	Power control device along Penwortham to Kirkby	2020
NOR2	Reconductor 13.75 km of Norton to Osbaldwick number 1 400 kV circuit	2022
OPN2	A new 400 kV double circuit between Osbaldwick and Poppleton and relevant 275 kV upgrades	2027
SHNS	Upgrade substation in the South Humber area	2031
THS1	Install series reactors at Thornton	2023
CDP1	Power control device along Cellarhead to Drakelow	2023
CBEU	Creyke Beck to Keadby advance rating	2022
CDHW	Cellarhead to Drakelow circuits thermal uprating	2022
CDP2	Power control device along Cellarhead to Drakelow	2023

Option code	Option description	EISD
CDP4	Alternative power control device along Cellarhead to Drakelow	2023
CKPC	Power control device along Creyke Beck to Keadby to Killingholme	2023
CRPC	Power control device along Cottam to Ryhall	2023
CWPC	Power control device along Cottam to West Burton	2023
DEPC	Power control device along Drax to Eggborough	2023
KWHW	Keadby to West Burton circuits thermal uprating	2022
KWPC	Power control device along Keadby to West Burton	2023
NOPC	Power control device along Norton to Osbaldwick	2023
NOR4	Reconductor 13.75 km of Norton to Osbaldwick number 2 400 kV circuit	2022
PWMS	Two 225 MVAr MSCs at Penwortham	2023
TDH1	Drax to Thornton 2 circuit thermal uprating and equipment upgrade	2022
TDH2	Drax to Thornton 1 circuit thermal uprating and equipment upgrade	2022
TDP2	Additional power control device along Drax to Thornton	2023

Offshore Coordination Project / Assumed network onshore reinforcements 45

Assumed network onshore reinforcements

NOA 2020 investments taken into consideration in our analysis

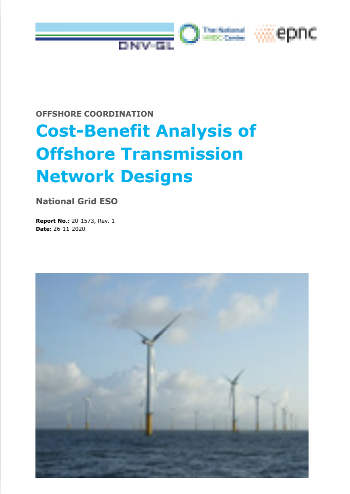
Option code	Option description	EISD
TDPC	Power control device along Drax to Thornton	2023
South Scotland & North England		
ECVC	Eccles synchronous series compensation and real-time rating system	2026
HAE2	Harker supergrid transformer 5 replacement	2023
HAEU	Harker supergrid transformer 6 replacement	2022
HSP1	Power control device along Fourstones to Harker to Stella West	2020
LNPC	Power control device along Lackenby to Norton	2020
NEP1	Power control device along Blyth to Tynemouth to Blyth to South Shields	2024
TLNO	Torness to north east England AC onshore reinforcement	2036
WHTI	Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit	2021
HSR1	Reconductor Harker to Stella West	2024

Option code	Option description	EISD
LNRE	Reconductor Lackenby to Norton single 400 kV circuit	2023
NEMS	225 MVAr MSCs within the north east region	2022
NEPC	Power control device along Blyth to Tynemouth and Blyth to South Shields	2023
Scotland		
CS35	Commercial solution for Scotland and the north of England	2023
DWNO	Denny to Wishaw 400 kV reinforcement	2028
ECU2	East coast onshore 275 kV upgrade	2023
ECUP	East coast onshore 400 kV incremental reinforcement	2026
HNNO	Hunterston East to Neilston 400 kV reinforcement	2023
WLTI	Windyhill to Lambhill to Longannet 275 kV circuit turn-in to Denny North 275 kV substation	2021
DNEU	Denny North 400/275 kV second supergrid transformer	2023
LBRE	Beauly to Loch Buidhe 275kV Double Circuit OHL reconductoring	2025

Option code	Option description	EISD
HVDC		
E2D2	Eastern Scotland to England link: Torness to Cottam offshore HVDC	2028
E2DC	Eastern subsea HVDC link from Torness to Hawthorn Pit	2027
E4D3	Eastern Scotland to England link: Peterhead to Drax offshore HVDC	2029
E4L5	Eastern Scotland to England 3rd link: Peterhead to the South Humber offshore HVDC	2031

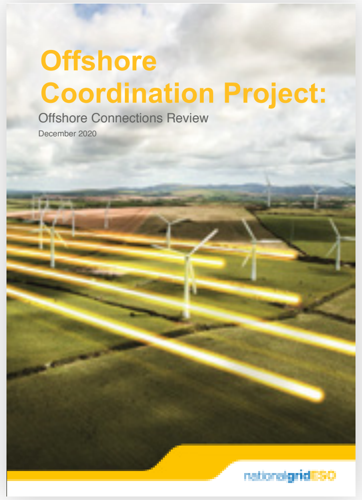
Offshore Coordination Project / Assumed network onshore reinforcements 46

Full reports

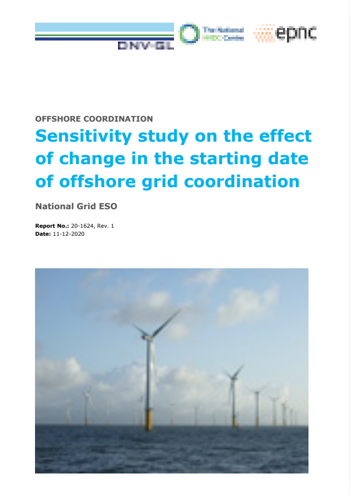


Cost-Benefit Analysis Report

Holistic Approach to Offshore Transmission Planning Report



Offshore Connections Review Report



Sensitivity analysis

Stakeholder annex – whole project overview of engagement completed. Includes ‘you said, we did’ consultation feedback

Offshore Coordination Project / Full reports 47

What has changed in our detailed reports?

If you read our detailed reports during our consultation you may find it useful to know what has changed in them since then. This area provides you with an overview of the changes.

Cost-Benefit Analysis Report

Page 12 - HVDC connection figure update

Page 13 - explanation elaborated

Page 14 - explanation on other costs added

Page 16 - graph added (not a new result, just new way of showing it)

Page 18 - graph added (not a new result, just a new way of showing it)

Page 20 - New information on breakdown of onshore and offshore costs split

Page 38 - New onshore landing area estimate

Several minor caveats throughout the document (results not affected, just adding explanations)

Holistic Approach to Offshore Transmission Planning Report

Page 14-15 - Table 2-2 High level KPIs (used as part of this assessment) - Deliverability Section

Page 58 - 4.1.10. KPIs Identified

Page 66 - 4.3.1. Key Elements of Developing Offshore Networks

Page 104 - 7.2. Analysis per Regional Zone

We have also made some amendments to these diagrams:

- Page 8, Figure 0-1 Illustrative comparison - Counterfactual and Integrated design approach.
- Page13, Figure 2-3 Comparison of project specific and integrated offshore network design approaches.
- Page 69, Figure 4-20 GB Implementation of Integrated Design (a) 2030. (b) 2050

Offshore Connections Review Report

This Report remains largely unchanged, the feedback provided has helped shape what we will start to progress in Phase 2 of the project.

Sensitivity analysis

This is a new document that has been published following stakeholder feedback. You will note in our key messages and summary of findings we have provided the views from this Report within them.

Offshore Coordination Project / What has changed in our detailed reports? 48

Glossary

Alternating current AC
Electric power transmission in which the voltage varies in a sinusoidal fashion, resulting in a current flow that periodically reverses direction. In Great Britain the direction is reversed 50 times each second.

Ancillary services
Services procured by a system operator to balance demand and supply and to ensure the security and quality of electricity supply across the transmission system. These services include reserve, frequency control and voltage control. In Great Britain these are known as balancing services and each service has different parameters that a provider must meet.

Bipole HVDC Configuration
The combination of two converter poles with a common low voltage return path, which if available will only carry a small unbalance current during normal operation.

Bootstrap
Subsea high voltage direct current (HVDC) link providing undersea connections between two points on the National Electricity Transmission System.

Boundary
The transmission system is split by boundaries that cross important power-flow paths where there are limitations in capability or where we expect additional bulk power transfer capability will be needed.

Cable corridor
The route taken by cables, either undersea or onshore.

Capacity
The maximum rated power output of an electricity generation technology - usually measured in Watts (or kilowatts (kW), megawatts (MW), gigawatts (GW) or terawatts (TW)).

Capital Expenditure Capex
Funds used by a company to acquire, upgrade and create assets such as IS systems, property, or equipment.

Carbon dioxide CO_2
The main greenhouse gas. The vast majority of CO_2 emissions come from the burning of fossil fuels.

Carbon intensity
A way of examining how CO_2 is emitted in different processes. Usually expressed as the amount of CO_2 emiitted per km travelled, per unit of heat created or per kWh of electricity produced.

Circuit breaker
A switch that connects or disconnects a circuit, generator, load or piece of transmission equipment and automatically shuts off the power when required to prevent damage.

Connection and Infrastructure Options Note CION
This is the document where the output of the CION optioneering process is recorded. It provides a joint record of the rationale for the selection of the overall preferred connection option from the assessment of technical, commercial, regulatory, environmental, planning and deliverability aspects.

Connection Use of System Code CUSC
The Connection and Use of System Code is the contractual framework for connecting to and using the National Electricity Transmission System (NETS).

Consenting Activity
Major infrastructure projects such as offshore wind farms require a type of consent known as 'development consent' under procedures governed by the Planning Act 2008 (PA2008). Development consent, where granted, is made in the form of a Development Consent Order (DCO).

Constraint costs
The costs incurred through paying generators to vary their power output when the electricity transmission system is unable to transmit power to the location of demand, due to congestion at one or more parts of the transmission network.

Contingency
Is the loss or failure of a part of the power system (e.g. a transmission line), or the loss/failure of individual equipment such as a generator or transformer. This is also called an unplanned "outage".

Contract for Difference CfD
A contract between the Low Carbon Contracts Company (LCCC) and a low carbon electricity generator, designed to reduce its exposure to volatile wholesale prices.

Cost-Benefit Analysis CBA
A method of assessing the benefits of a given project in comparison to the costs. This tool can help to provide a comparative base for all projects to be considered.

Decarbonisation
The process of removing carbon emissions (e.g. generated by burning fossil fuels) from our economic and social activities.

Decarbonisation Action Plan
A document published by Ofgem which sets out the actions Ofgem will take over the next 18 months to help make low-cost decarbonisation a reality.

Demand Centres
Energy demand centre is the form of energy consumption that uses electric energy. Electric energy consumption is the actual energy demand made on existing electricity supply.

Department for Business, Energy and Industrial Strategy BEIS
A UK Government department with responsibilities for business, industrial strategy, science, innovation, energy, and climate change.

Direct Current DC
Electrical current that moves in one direction only.

Direct Current Circuit Breakers DCCBs
A DC switch that connects or disconnects a circuit, generator, load or piece of transmission equipment and automatically shuts off the power when required to prevent damage.

Dynamic performance
Fast response to changes in frequency, voltage and current on the transmission network to maintain stable network operation.

Forward Plan
Published each financial year between 2018/19 and 2020/21, our Forward Plan describes what the ESO is planning to do to deliver benefits for our customers and stakeholders. It includes a set of criteria for our performance to be measured against.

Future Energy Scenarios *FES*
The *FES* is a range of credible pathways for the future of energy out to 2050. They form the starting point for our transmission network and investment planning, and are used to identify future operability challenges and potential solutions.

Gigawatt GW
A unit of power. 1 GW = 1,000,000,000 watts.

Gigawatt Hour GWh
1,000,000,000 watt hours, a unit of energy.

Great Britain GB
A geographical, social and economic grouping of countries that contains England, Scotland and Wales.

Greenhouse gas
A gas in the atmosphere that absorbs and emits radiation within the thermal infrared range.

Grid Code
Specifies the technical requirements for connection to, and use of, the National Electricity Transmission System.

Grid curtailment
This is when the output from a generation unit connected to the electricity system is reduced due to operational balancing.

Grid Losses (transmission losses)
Power lost through the energisation and transmission of energy through the transmission network.

High Voltage Alternating Current HVAC
AC power transmission at voltages above 110 kilovolts (kV).

High Voltage Direct Current HVDC
DC power transmission at voltages above 110 kilovolts (kV).

Infeed
The provision of power from generators onto the National Electricity Transmission System.

Interconnector
Transmission assets that connect the GB market to Europe and allow suppliers to trade electricity or gas between markets.

Integration
We have two integrated network designs covering integration commencing 2025 and 2030. The designs assume that works offshore are coordinated, where appropriate, from 2025 or 2030, to enable transmission asset sharing to bring the electricity onshore.

Key Performance Indicator KPI
A measurable value that demonstrates progress towards the intended result.

Landing Point
The location where a submarine or other underwater cable makes landfall.

Leading the Way Scenario LW
One of the 2020 *Future Energy Scenarios* (*FES*) in which it is assumed that GB decarbonises rapidly with high levels of investment in world-leading decarbonisation technologies. Our assumptions in different areas of decarbonisation are pushed to the earliest credible dates. Consumers are highly engaged in acting to reduce and manage their own energy consumption. This scenario includes the highest and fastest improvements in energy efficiency to drive down energy demand, with homes retrofitted with insulation such as triple glazing and external wall insulation, and a steep increase in consumer participation in smart energy services. Hydrogen is used to decarbonise some of the most challenging areas of society such as some industrial processes, with this Hydrogen produced solely from electrolysis powered by renewable electricity. Leading the way achieves 40 GW of offshore wind by 2030 and meets the UK target for net zero greenhouse gas emissions in 2050.

Least worst regret
A decision making tool that makes recommendations based on which options/strategy produce the least 'regret' across all of the scenarios analysed.

Load factor
An indication of how much a generation plant or technology type has output across the year, expressed as a percentage of maximum possible generation. These are calculated by dividing the total electricity output across the year by the maximum possible generation for each plant or technology type.

Loss of Load Expectation LOLE
Used to describe electricity security of supply. It is an approach based on probability and is measured in hours per year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. In Great Britain the standard is 3 hours per year but this does not mean there will be loss of supply for 3 hours per year. It gives an indication of the amount of time, across the whole winter, which the Electricity System Operator (ESO) will need to call on balancing tools such as voltage reduction, maximum generation or emergency assistance from interconnectors. In most cases, loss of load would be managed without significant impact on end consumers.

LVDC return cable
Low voltage direct current return cable. During normal operation the LVDC cable carries only a small unbalance current. Upon a single HVDC cable fault, the LVDC return cable path takes over the full current in the healthy circuit and the faulty circuit can be isolated.

Mega tonnes of CO_2 equivalent $MtCO_2e$
The equivalent of 1,000,000 tonnes of carbon dioxide; the standard unit for measuring national and international greenhouse gas emissions.

Megawatt MW
A unit of power. 1 MW = 1,000,000 watts.

Megawatt hour MWh
A unit of energy. 1MWh = 1,000,000 watt hours.

Meshed connections
Is a network design, where the exact flow of power on any particular line of the network depends on the combination of loads and generation at different locations, and the characteristics of the lines.

National Electricity Transmission System NETS
The network and assets infrastructure that supports the electricity transmission system in England, Scotland and Wales.

National Grid Electricity System Operator (ESO) ESO
National Grid Electricity System Operator (ESO) moves electricity to where it is needed on the transmission system, balancing supply and demand on a second by second basis in Great Britain. The ESO does not own any transmission assets, the electricity transmission system is owned by National Grid Electricity Transmission, Scottish Hydro Electricity Transmission and SP Transmission. Since April 2019 the ESO has been a legally separate company within the National Grid Group and has its own regulation, incentive scheme and company board.

Net zero greenhouse gas emissions
When the total of all greenhouse gasses emitted in a year reaches zero, after all emissions and all carbon sequestration has been accounted for. This is the current UK target for 2050.

Office of gas and electricity markets Ofgem
The UK's independent National Regulatory Authority, a non-ministerial government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers.

Offshore
This term means wholly or partly in offshore waters.

Offshore HVDC Converter Platform
The offshore (in the sea) high voltage direct current converter platform converts alternating current (power that flows in alternating directions) into direct current (power that can only flow in one direction).

Offshore HVDC switching platforms
The offshore high voltage direct current switching platforms that interconnects two or more direct current circuits using circuit breakers or disconnectors to form a multi-terminal HVDC network.

Offshore Transmission Network Owner OFTO
A transmission owner who assumes responsibility for offshore transmission assets. An OFTO is competitively appointed by Ofgem through a tender process and is awarded an OFTO licence.

Offshore Transmission Network Review OTNR
A review, led by BEIS, into the way that the offshore transmission network is designed and delivered, consistent with the ambition to deliver net zero emissions by 2050. The ESO Offshore Coordination Project forms part of the OTNR.

Onshore
This term refers to assets that are wholly on land.

Onshore converter station
Onshore infrastructure on the National Electricity Transmission System that converts between HVDC and HVAC.

Operating expenditure Opex
Operational expenditure which is an ongoing cost for running a product, business, or system.

Operational Limits
These are the operational parameters that the Electricity National Control Centre must adhere to in order to operate the system safely and reliably. These include factors such as frequency and voltage.

Power System Analysis
A group of studies used to analyse a power system's response to events over different time periods.

Power transfer
The transport of power from one point to another.

Radial
Direct single connection of an offshore wind farm to the onshore transmission network without connection to other points.

Reinforcements
Additional grid infrastructure implemented to ensure the National Electricity Transmission System can accommodate existing and future generation and demand.

Revenue = Incentives + Innovation + Outputs RIIO
Ofgem's regulatory framework that sets price controls to determine the amount network companies can earn from the services they provide.

Security and Quality of Supply Standard SQSS
A set of standards used in the planning and operation of GB's National Electricity Transmission System, including both onshore and offshore.

Sensitivity Analysis
In this report, a study on the effect of change in the starting date of offshore grid integration.

Status Quo
The status quo assumes that nothing changes in approach between today and 2050 in regards to planning or processes of connecting offshore wind farms. The current approach is project by project, radial connections from onshore to offshore windfarms.

System Operator-Transmission Owner Code STC
The System Operator Transmission Owner Code defines the relationship between the transmission system owners and the system operator.

System Stability
The stability of frequency, voltage and the ability of a network user to remain connected to the system during normal operation, during a fault and after a fault.

Technology Readiness Level TRL
This is a scale for measuring the maturity of technology, from basic research through test, launch and operations. It indicates where a system is on development lifecycle and its readiness for operational use.

Ten Point Plan for a Green Industrial Revolution
A government published document that sets out the approach government will take to build back better, support green jobs, and accelerate our path to net zero.

Terawatt hour TWh
A unit of energy. 1 TWh = 1,000,000,000,000 watt hours.

The Crown Estate
Is an independent commercial business, created by an Act of Parliament, with a diverse portfolio of UK buildings, shoreline, seabed, forestry, agriculture and common land. They are responsible for the leasing of seabed offshore in England and Wales.

The Crown Estate Scotland
Manages land and property owned by the Monarch in right of the Crown in Scotland. The business was set up following the Scotland Act 2016 and pays all revenue profit to the Scottish Consolidated Fund. They are responsible for the leasing of seabed offshore in Scotland.

Transmission Owner TO
A collective term used to describe the three electricity transmission asset owners within Great Britain, namely National Grid Electricity Transmission, Scottish Hydro Electric Transmission Limited and SP Transmission plc.

Under-utilisation
Use of assets to a lesser extent than planned. This may result from offsore wind farms not connecting to infrastructure built to facilitate the integrated design.

United Kingdom of Great Britain and Northern Ireland UK
A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland. The 2050 Net Zero Emissions Target is on a UK basis (i.e. includes Northern Ireland as well).

Voltage control
The regulation of connection point voltage to within statutory limits.