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for energy consumers

Consultation

Changes intended to bring about greater coordination in the development of offshore energy networks

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We are consulting on three key components of the Offshore Transmission Network Review, which seeks to increase the levels of coordination in the design and delivery of offshore transmission network infrastructure. We welcome input from all stakeholders. We would like views from people with an interest in offshore transmission, transmission, offshore generation and interconnection. We particularly welcome responses from all stakeholders, particularly developers who are embarking on coordination projects now or in the future.

This document outlines the scope, purpose and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at **Ofgem.gov.uk/consultations**. If you want your response – in whole or in part – to be considered confidential, please tell us in your response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

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Contents

1. Introduction

Section summary

This section of the consultation introduces the Offshore Transmission Network Review and explains how the topics Ofgem is consulting on now fit into the broader context.

Overview

1.1. The current approach to designing and building offshore transmission was developed when offshore wind was a nascent sector and industry expectations were just 10GW by 2030. This approach has contributed to the maturing of the sector and significant cost reductions in offshore wind energy. This has helped position the UK at the forefront of global offshore wind deployment.

1.2. In light of the new, ambitious offshore wind target of 40GW by 2030 as set out in the Prime Minister's Ten Point Plan[1], and the expectation of more offshore wind beyond that to deliver net-zero by 2050, radial offshore transmission links are not likely to be economically and environmentally acceptable for many areas. It is also increasingly clear that the current approach will not be sufficient to deliver 40GW of offshore wind by 2030, or potentially 100GW by 2050 to support net zero[2].

1.3. The Offshore Transmission Network Review (OTNR) was launched in July 2020 by the Energy Minister, in support of achieving these targets set out by the Government. The aim of the OTNR is to ensure that future connections for offshore wind are delivered with increased coordination while ensuring an appropriate balance between environmental, social and economic costs.

[1] The ten point plan for a green industrial revolution - GOV.UK (www.gov.uk)
[2] Offshore transmission network review - GOV.UK (www.gov.uk)

1.4. The importance of greater coordination in the development of offshore transmission infrastructure was set out in Ofgem's Decarbonisation Action Plan, published in February 2020[3].

1.5. Delivering 40GW of offshore wind by 2030 is challenging and requires a rate of deployment of >3GW per year. This equates to 1 turbine being installed each weekday throughout the whole of the 2020's. The regulatory framework for developing and connecting offshore wind is complex and involves multiple government departments, regulators, statutory bodies, devolved administrations and industry parties.

1.6. The length of time taken to develop an offshore wind farm is substantial, as illustrated in Figure 1 From seabed leasing, through connections, planning and consenting processes to CfD auction and OFTO tender, the offshore wind journey requires significant commitment of time. Further, the design of the connection is often determined relatively early in the process and thus, changes to ongoing projects especially those far along in the development process can carry substantial risk to project success.

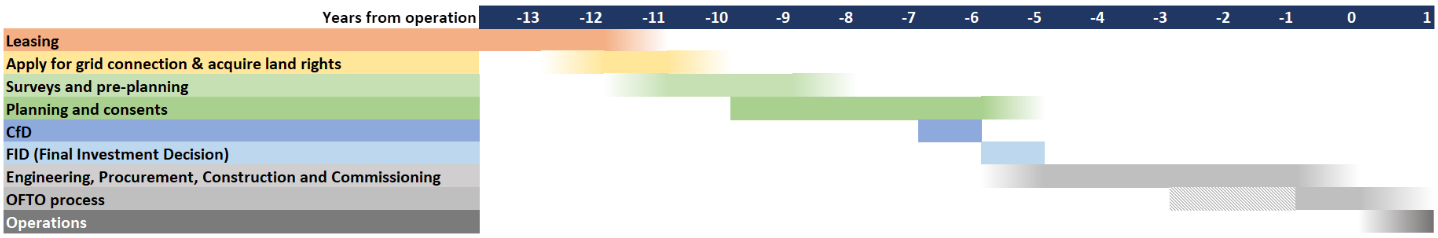

Figure 1 Indicative offshore wind development timeline[4].

1.7. Therefore, the introduction of any form of coordination will be a balancing act between maintaining the pace of delivery required to meet 40GW by 2030 and introducing changes as soon as practically possible to maximise social, economic and environmental benefits.

What are we consulting on?

1.8. To achieve the deliverables of the OTNR there are four workstreams operating in parallel, with varying degrees of Ofgem involvement. Figure 2 describes the objectives and

[3] Ofgem's Decarbonisation Action Plan | Ofgem
[4] This timeline may differ for different technologies and in the Scottish regime.

regulatory scope of each workstream. The Early Opportunities, Pathway to 2030, and Enduring Regime workstreams divide policy development and industry engagement into three temporal workstreams. This is to enable the OTNR to design effective interventions that target projects at different stages of the development journey. The Multi-Purpose Interconnector (MPI) workstream works across all three temporal workstreams to make tactical changes that will enable the delivery of early opportunity MPIs, while also considering an enduring regime to effectively deliver projects from 2030 onwards.

1.9. The remit of change in the Early Opportunities and Pathway to 2030 workstreams is primarily led by Ofgem. In the Enduring Regime and MPI workstreams, changes are primarily led by BEIS. BEIS will be consulting stakeholders on its workstream areas later in the year.

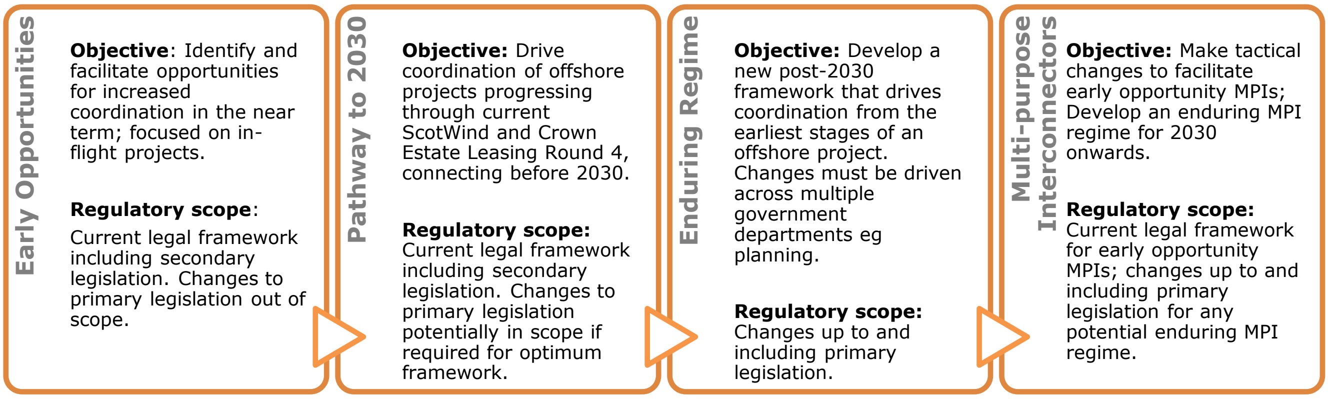

Figure 2 The objective and regulatory scope of the four OTNR workstreams

1.10. This Ofgem consultation is the first in a series of consultations that will be published as part of the OTNR. This policy consultation covers three key components of the review and we welcome input from all stakeholders:

- **Early Opportunities.** We set out proposed changes to the existing regulatory regime to enable developers to make changes to coordinate in-flight projects.

- **Pathway to 2030.** We set out the proposed approach for a holistic onshore and offshore network design to enable coordination in the delivery of the 40GW by 2030 target; we are specifically seeking to capture the current ScotWind and Crown Estate Leasing Round (LR4) projects. We also identify high level options for delivery models for any required coordinated of offshore transmission infrastructure.

- **Multi-Purpose Interconnectors (MPIs).** We explore the feasibility of using the existing legal framework to facilitate early opportunity MPI projects. This section contains questions for stakeholders from both BEIS and Ofgem.

The benefits of acting now

1.11. The current framework for connecting offshore wind to shore was designed with the need to de-risk the delivery of offshore wind projects in mind. This was done by allowing developers to manage the construction of their own route to market, which further helped introduce competition into the ownership of offshore transmission assets. As a result, this introduced new innovative sources of finance which reduced costs to consumers.

1.12. However, this approach has also resulted in wind farms constructing their own individual routes to shore in the form of radial, point-to-point connections. Due to the cumulative environmental and social impacts of transmission infrastructure, both onshore and offshore, this radial approach now presents a major barrier to the delivery of increasingly ambitious offshore wind targets of 40GW by 2030 and net zero by 2050.

1.13. Analysis carried out by the Electricity System Operator (ESO), commissioned by Ofgem, has concluded that greater coordination from 2025 could deliver up to £6bn in consumers savings compared to the status quo, and that the number of new electricity infrastructure assets associated with offshore connections, including cables and landing points, could reduce by ~50%[5].

1.14. Whilst coordination can reduce the overall amount of infrastructure required, achieving our 2030 targets and delivering net zero will ultimately require more infrastructure than we have today (on and offshore) – both to generate power through offshore wind and to transmit that power to where it is needed. It is therefore vital that we ensure future infrastructure is planned and delivered in the most effective way while achieving an appropriate balance between economic, environmental and societal costs.

1.15. Given the long lead times for constructing offshore wind farms, many projects connecting ahead of 2030 are already in-flight and relatively advanced in their development. Introducing changes to such projects risks delaying them and carries contractual and

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[5] The final Phase 1 report in our Offshore Coordination project | National Grid ESO

commercial implications, and consequently might impact our ability to meet 2030 targets. The OTNR therefore seeks to strike the right balance between delivering coordination in how offshore wind is connected and maintaining the required pace of delivery to achieve Government ambitions.

1.16. Moving from a developer-led and incremental model of offshore network development to a more centrally planned and coordinated approach represents a major shift for the industry and has significant links to policy areas across Ofgem, such as onshore transmission, onshore competition, network planning, charging and ESO RIIO2 deliverables. It is therefore important that we understand the risks and dependencies to enable effective and robust policy implementation, and we welcome input from stakeholders on this.

1.17. Through this consultation, we seek views on how we can resolve the main barriers to coordination in the short and medium term.

Our work so far

1.18. In August 2020, the Department for Business Energy and Industrial Strategy (BEIS) and Ofgem issued a joint Open Letter[6] in which we called for stakeholder views to support the OTNR. In particular, we sought views from stakeholders who were either already pursuing some level of coordination or had identified an opportunity to do so whether on a local, national or international level (such as considering anticipatory investment in one project to enable a future project, or combining offshore wind and interconnector assets).

1.19. We received 48 responses from a range of stakeholders, sharing views on perceived barriers to coordination and proposing specific projects developers might want to take forward. Stakeholders identified areas, within the existing offshore regime, as well as wider policy frameworks and processes that, in their view, presented significant barriers to enabling coordination. These views are summarised in the BEIS and Ofgem Open Letter response[7], published in December 2020.

[6] Increasing the level of coordination in offshore electricity infrastructure: BEIS and Ofgem open letter to developers of offshore wind generation, electricity transmission licensees, and other interested parties | Ofgem
[7] BEIS and Ofgem joint response to the Open Letter engagement

1.20. The creation of the four OTNR workstreams reflects the feedback received in those responses. As we explained in our Open Letter response, we committed to reviewing the existing framework to find flexibilities and minor changes to enable coordination, and we identified that an alternative approach to anticipatory investment might also be an area on which we should focus.

1.21. Since publishing the Open Letter response, Ofgem and BEIS have engaged stakeholders extensively. This includes through an industry webinar[8], multiple rounds of developer bilateral meetings, industry roundtable events, an OTNR industry expert group, and the OTNR Quarterly Newsletter[9]. These engagements have enabled us to explore key barriers to coordination in more detail with industry and take a wide range of views into account. Barriers and opportunities raised by industry have been considered with key OTNR project partners such as the Electricity System Operator, the Crown Estate, and Crown Estate Scotland.

Ofgem approach to policy assessment

Policy Assessment Criteria

1.22. Through the OTNR governance structures, project partners have agreed a consistent set of Policy Assessment Criteria that can be used across OTNR workstreams. The serve as a tool for the OTNR partners to aid the evaluation of policy choices at a high level, as opposed to detailed economic or engineering decisions at specific sites. They are intended to aid decision making. There are four overarching themes: Deliverability of OTNR policy and Net Zero; Economics and Commercials; Environmental and Societal Impact; and Consumer and System impact. While they were designed to be consistent with relevant wider objectives such as the Government's Ten Point Plan for a Green Revolution[10] and organisational duties, it is for the relevant decision-making body to use the results of any policy assessment based on these criteria when making decisions in accordance with relevant objectives and duties. To this end, Ofgem will use the assessment criteria to shape policy options and evaluate options

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/946574/presentation-17-10-20.pdf
[9] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/979088/OTNR_Q1_2021_Newsletter.pdf
[10] The ten point plan for a green industrial revolution - GOV.UK (www.gov.uk)

but will be steered by its statutory duties to make decisions that are in the best interests of consumers. The Policy Assessment Criteria are provided in an Appendix 3 to this consultation.

Ofgem's principal objective

1.23. While the goals were set at the state level through the Ten Point Plan, Ofgem is seeking to deliver the outcomes at the GB level because Ofgem is the competent authority regulating electricity and gas in GB (ie for England, Wales and Scotland). Our approach to developing policy under the OTNR will be driven by our strategy and priorities as the GB energy regulator[11], which are set out by our governing body, the Gas and Electricity Markets Authority ('the Authority'). Our principal objective is to protect the interests of existing and future consumers and it is important to note that these interests are taken as a whole, including consumers' interests in the reduction of greenhouse gases and the security of the supply of gas and electricity to them. We will therefore take this into account as we consider and assess options to progressing policy change, particularly in the allocation of risk associated with increased levels of anticipatory investment and the move to a more centralised approach to offshore network development.

Next steps

1.24. This summer consultation marks the **first stage** in our process for developing and testing policy options with stakeholders. However, we acknowledge that while we are at the early stages of policy and regulatory change, it is important for both Ofgem and industry to move quickly if we are to be successful in progressing change to facilitate more coordination in the near term where it is in energy consumers' interests.

1.25. We therefore intend to hold **structured engagement with stakeholders** throughout the course of the consultation window, and beyond. The purpose of this is to explore and gather as much evidence on issues, barriers, and opportunities as possible to feed into our next stage, which is to firm up minded-to proposals for consultation.

1.26. We intend to reach out to stakeholders in due course, but please get in touch to let us know if you have suggestions around how this could work best.

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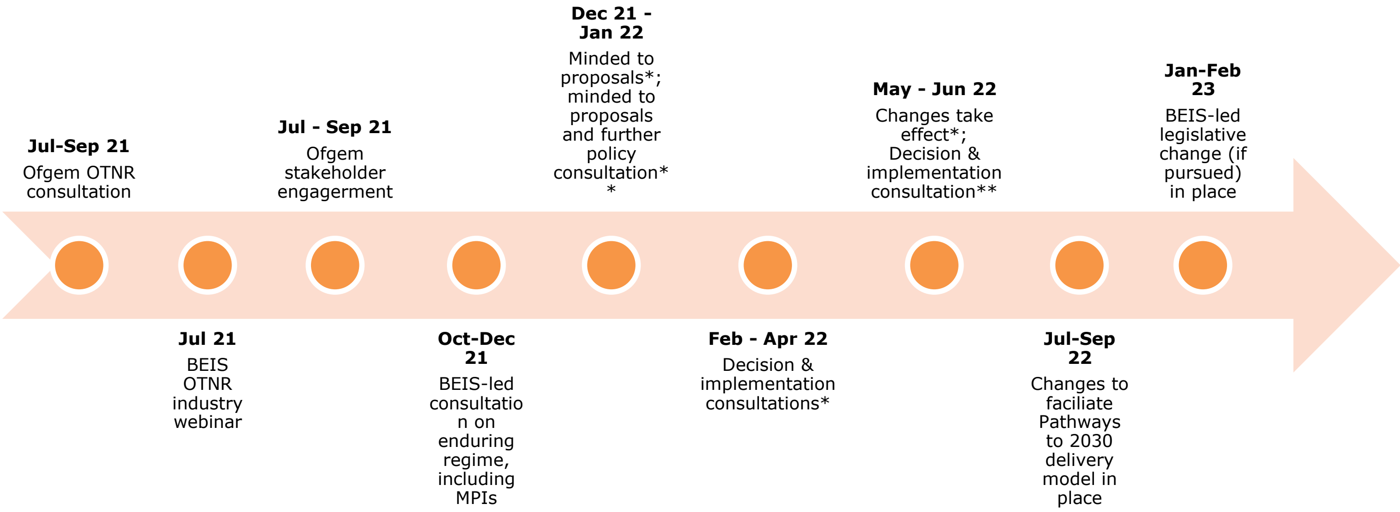
[11] Our powers and duties | Ofgem

1.27. Figure 3 provides an **indicative summary of the key stages** to BEIS and Ofgem's activities under the OTNR. Each section in this consultation provides more detail on next steps for the relevant workstream area.



*Early Opportunities and MPIs;

**Pathway to 2030

Figure 3 Indicative summary of Ofgem and BEIS key activities under the OTNR

1.28. BEIS will be publishing a consultation later this year on a future enduring regime for projects connecting beyond 2030, which will also consider MPIs.

1.29. This will involve the exploration of more interventionist change to deliver coordination, through expansive regulatory review, which could include potential changes to primary legislation.

Context and related publications

BEIS – Offshore Transmission Network Review OTNR

BEIS/Ofgem Open Letter 24 August 2020 Open Letter

BEIS/Ofgem Joint Response to the Open Letter Engagement 18 December 2020
Response to Open Letter

Offshore Transmission Network Review – Webinar Presentation – 17 December 2020
OTNR Webinar Presentation

Offshore Transmission Network Review – Webinar Q&A – December 2020
Webinar Q&A

Offshore Coordination Phase 1 Final Report – 16 December 2020

[Offshore Coordination Phase 1 Final Report]

Integrated Transmission Planning and Regulation (ITPR) project: Final Conclusions 17 March 2015 [Integrated Transmission Planning and Regulation (ITPR) project: final conclusions (ofgem.gov.uk)]

How to respond

1.30. We want to hear from anyone interested in this consultation. Please send your response to the person or team named on this document's front page.

1.31. We've asked for your feedback in each of the questions throughout. Please respond to each one as fully as you can.

1.32. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

Your response, data and confidentiality

1.33. You can ask us to keep your response, or parts of your response, confidential. We will respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

1.34. If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

1.35. If the information you give in your response contains personal data under the General Data Protection Regulation 2016/379 (GDPR) and domestic legislation on data protection, the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 4.

1.36. If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

General feedback

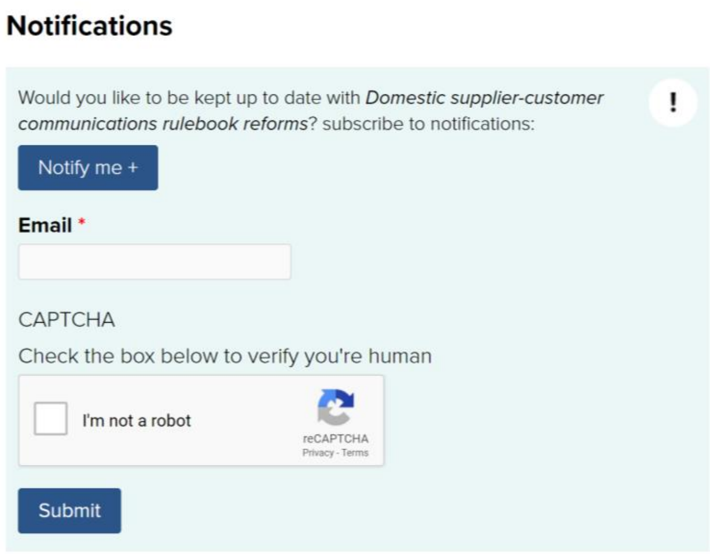
1.37. We believe that consultation is at the heart of good policy development. We welcome any comments about how we've run this consultation. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

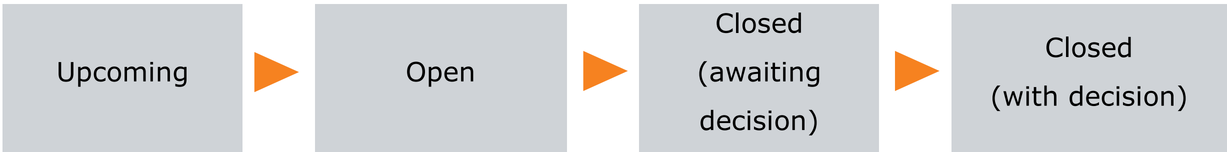
1.38. Please send any general feedback comments to stakeholders@ofgem.gov.uk

How to track the progress of the consultation

1.39. You can track the progress of a consultation from upcoming to decision status using the 'notify me' function on a consultation page when published on our website. Ofgem.gov.uk/consultations.



1.40. Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:



2. Early Opportunities

Section summary
This section of the consultation focuses on the Early Opportunities workstream. We set out the scope and objective of the workstream, the barriers faced by industry in progressing 'early opportunity' projects, and how Ofgem proposes these barriers are overcome.

We are seeking views on the approach and proposals we have set out in this consultation, which describe the principles and outcomes that we want to achieve through changes to the framework.

Introduction

Objective and scope of Early Opportunities

2.1. Historically there has been a lack of coordination in the development of offshore transmission infrastructure. This lack of coordination occurs for a number of reasons, including the broad commercial and regulatory landscape within which developers operate. Given the scale of ambition for offshore wind, the existing model may not be appropriate in the future. This is why the OTNR was launched.

2.2. Offshore wind farms and their associated infrastructure have long lead times (it can take around ten years for an offshore wind farm to move from seabed lease to operation). There are a number of potential unintended consequences that could result from making policy and regulatory changes where developments have such long lead times. Developments could be delayed or require substantial change; both of these could increase cost and risk. In this workstream we want to increase the ability of projects in to coordinate and to realise benefits of coordination. We do not want to slow the rate of development, thereby putting at risk the Government's target of 40GW by 2030; however, there are also wider factors out of our control like planning and consenting that will impact timelines. By facilitating the coordination, and potentially reducing landing points we believe there is a better chance of projects reducing costs and reaching commercial operation on schedule. The intent of the proposals is to allow developers to choose to make changes by giving them certainty on how expenditure on transmission infrastructure will be treated in different scenarios.

2.3. The objective of the Early Opportunities workstream is to facilitate greater coordination in the connection of offshore wind projects which are at a relatively advanced stage of the development process. These projects are likely to have undertaken a significant amount of design, development, planning and consenting work. For offshore wind projects, these are projects which are expected to participate in Contract for Difference Allocation Round 5 or Round 6[12].

2.4. In our joint BEIS-Ofgem open letter, in August 2020, we invited stakeholders to share their views on the OTNR, identify perceived barriers to coordination and identify opportunities for coordination. In our response, in December 2020, we described the scope of the Early Opportunities workstream, including exploring potential amendments to existing regulation and further consideration of anticipatory investment. We noted our ongoing discussions with project developers to identify potential opportunities and the changes that would be needed to allow them to progress, and we flagged our intent to consult on specific regulatory changes in 2021.

2.5. We have subsequently engaged with a number of developers on possible coordination for inflight projects and a number of proposals have come forward. As a result of this engagement we have identified six concepts into which projects can be categorised. This workstream is intended to facilitate more coordination through these generic concepts (rather than specific projects) either by leveraging flexibility within the existing regime or making near-term changes to the current overall regulatory framework.

2.6. Our proposals in this section are focussed on facilitating coordination with an opt-in for developers, rather than enforcing coordination. We recognise that these projects are at an advanced stage of development where much of the detailed design and planning work has already been completed. However, we want to enable developers to be ambitious, and we encourage developers to proactively consider opportunities for coordination with others in the same region where they are not already doing so.

Approach to consultation

2.7. In this consultation we have set out some of the barriers faced by industry in progressing early opportunity projects and proposed ways to overcome them. We are

[12] These allocation rounds are expected to take place in 2023 and 2025, respectively.

consulting on the early opportunity concepts that have been identified following engagement with developers (as noted above in paragraph 2.5). The proposals we have set out describe principles and outcomes that we want to achieve through changes to the frameworks.

2.8. This consultation provides our initial proposals and further clarity that, together, should facilitate greater coordination in the short term. In developing our proposals for consultation, we are not seeking to facilitate specific projects, rather a number of concepts that these projects are seeking to implement.

2.9. We have set specific questions but are seeking views from stakeholders on identified barriers, proposed outcomes, and approach to achieving them.

Early Opportunities Concepts

Background

2.10. Our current work follows from an earlier review we concluded in 2015. The Integrated Transmission Planning and Regulation (ITPR) project: final conclusions[13] set out a number of changes intended to bring about a more coordinated system. These included giving the Electricity System Operator (ESO) new responsibilities. The ESO took on an increased role for network planning and development onshore and offshore following ITPR. Since its implementation, the ESO has been able to propose wider network benefit investment (WNBI), ie works that a developer of an offshore wind farm could deliver when building an offshore transmission link that would provide wider system benefits.

2.11. The other element of ITPR relevant to offshore coordination is that we committed to provide clarity on how the cost of generator focussed anticipatory investment (GFAI) would be recovered where one developer made an investment on assets that would benefit a different project. To date, however, neither the GFAI or WNBI frameworks have been used, in part due to incentives inherent in the wider commercial and regulatory frameworks.

2.12. Our engagement with industry so far has sought views on why offshore coordination has not been taken forward to date, and which aspects of the existing commercial or regulatory frameworks pose barriers that have prevented coordination between projects. In

[13] Integrated Transmission Planning and Regulation (ITPR) project: final conclusions | Ofgem

this consultation we have set out some of the barriers faced by industry in progressing early opportunities for coordination and proposed ways to overcome them. We are consulting on the early opportunity concepts that have been identified following engagement with developers (as noted above in paragraph 2.5).

2.13. Each concept provides a different blend of potential benefits. Some emphasise minimising the amount of new infrastructure required or reduce the number of landing points ie where infrastructure makes landfall. Other concepts emphasise the provision of wider system benefits eg reducing the need for onshore reinforcement. Our inclusion of a concept here is not intended to indicate our view on the potential benefits of a given scheme. The developer of a project would need to demonstrate the benefits on a case by case basis.

The concepts

Shared offshore transmission system

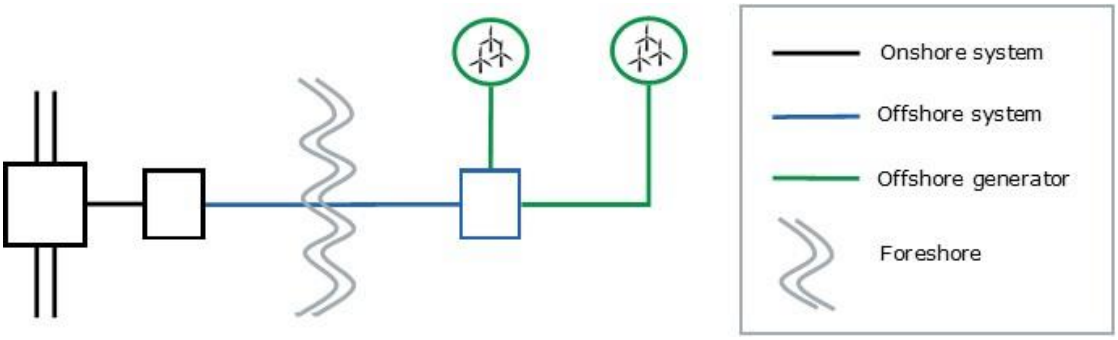


Figure 4 Shared offshore transmission system concept

2.14. This concept involves multiple generators using a single offshore transmission system. This concept emphasises a reduction in landing points and the number of substations compared to the business as usual radial links.

Quasi bootstrap

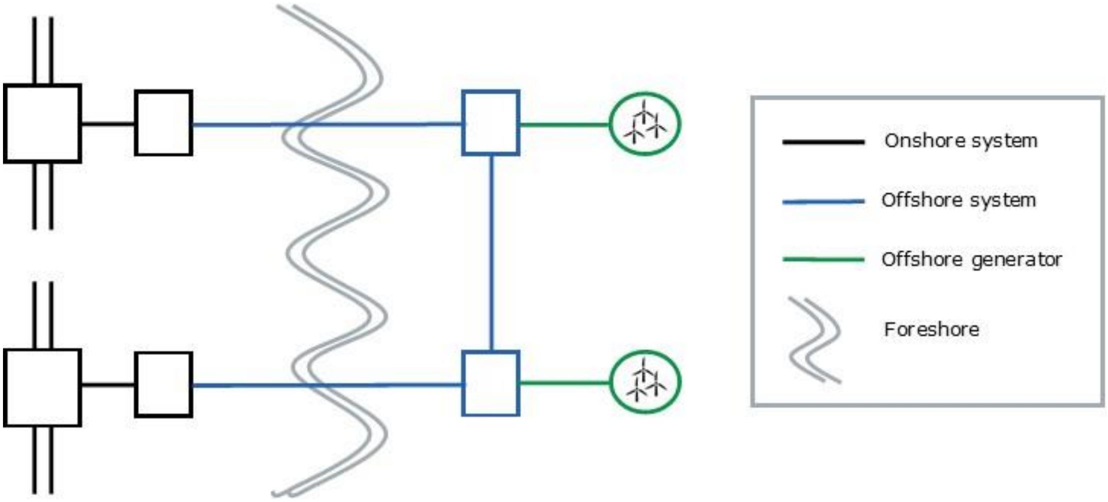


Figure 5 Circuit which connects two (or more) offshore substations that are not connected to a single common substation

2.15. This concept involves the installation of a circuit between the respective offshore substations of two offshore generators, where the offshore substations are not connected to a single common onshore substation. This concept emphasises the potential to provide wider system benefits by reinforcing the onshore system in the form of a quasi-bootstrap. It would not reduce infrastructure or landing points, but is an example of coordination.

2.16. The offshore substations may be located on a single platform. This concept may deliver additional transmission system boundary capacity or alternative system benefits. This concept is distinct from an Offshore Interlink, which is described in CUSC section 14[14] as a circuit which connects two offshore substations that are connected to a Single Common Substation onshore. Where a developer proposes this, they will need to demonstrate the need to the wider system of the additional investment – this may mean the proposal would need to be considered as part of the Network Options Assessment (NOA) [15].

[14] CUSC Section 14 download (nationalgrideso.com)
[15] Network Options Assessment (NOA) | National Grid ESO

Multi-purpose interconnector (interconnector-led model)

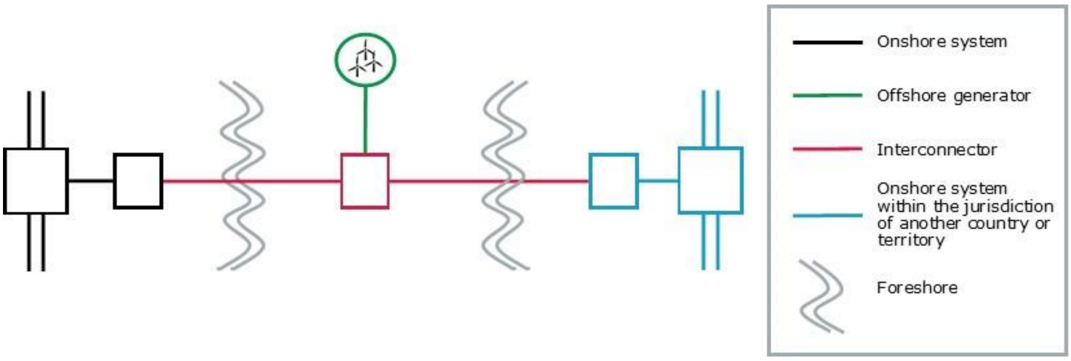


Figure 6 Multi-purpose interconnector (interconnector-led model) concept between Great Britain and a place within the jurisdiction of another country or territory

2.17. This concept involves the connection of an offshore generator in the GB market to transmission infrastructure that classified as an interconnector. This concept like the one below emphasises the reduction in landfall points required to connect a given amount of generation and interconnection to the wider system.

Multi-purpose interconnector (OFTO-led model)

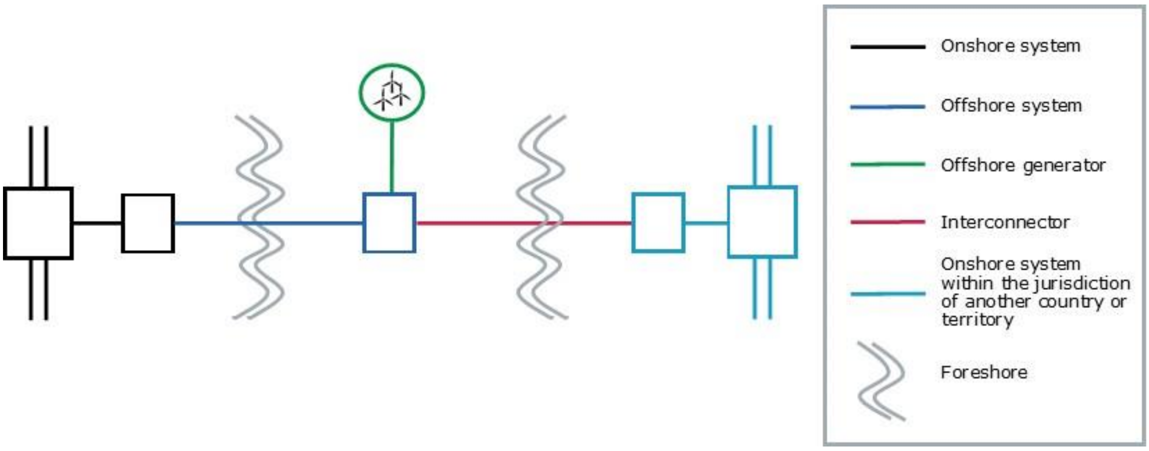


Figure 7 Multi-purpose interconnector (OFTO-led model) concept between Great Britain and a place within the jurisdiction of another country or territory

2.18. This concept involves the connection of an offshore generator to transmission infrastructure comprised of distinct elements that are classified differently. One element is classified as an interconnector, and the other is classified as an offshore transmission system.

This concept like the one above emphasises the reduction in landfall points required to connect a given amount of generation and interconnection to the wider system.

Connection to a TO owned bootstrap

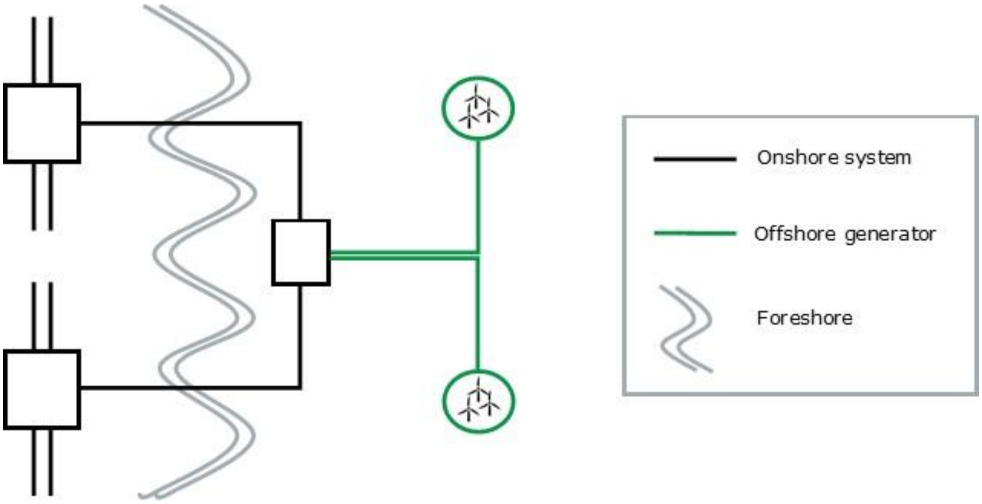


Figure 8 Connection of an offshore generator to infrastructure that is located offshore and owned by a Transmission Owner (TO)

2.19. This concept involves the connection of an offshore generator to a subsea electricity link between two points in the onshore transmission system, which is owned by a TO. These onshore to onshore links are known colloquially as 'bootstraps'. This concept emphasises the reduction in landing points and infrastructure required to connect generation to shore.

Connection of electricity storage or a demand user to an offshore transmission system

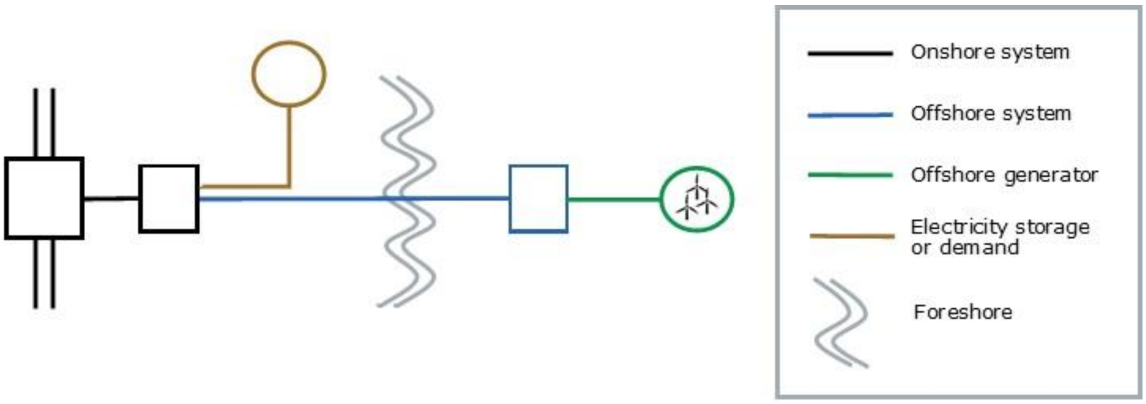


Figure 9 Connection of electricity storage or a demand customer to an offshore transmission system

2.20. This concept may involve the connection of electricity storage or a demand customer such as an electrolyser to the onshore or offshore elements of an offshore transmission system. The principle could also allow for the electrification of oil and gas platforms. This would allow for coordination across energy vectors, not only of electricity transmission infrastructure.

Question 1: Are there any concepts we have not identified and which developers may wish to progress?

Ofgem proposals to facilitate Early Opportunities Concepts

Background

2.21. From our engagements with developers, OTNR partners and our own analysis, we have identified a number of barriers to implementing the six concepts described above. This follows our Open Letter and subsequent engagement with developers. The remainder of this chapter focusses on the actions we either propose to take ourselves or actions to be taken forward by industry to address these barriers.

2.22. The biggest barrier we have identified following engagement with developers is the management of anticipatory investment (AI) risk – common to all multi development projects. According to developers this risk manifests for two reasons: (1) the competitive pressures of the CfD process, and, (2) our cost assessment processes and cost recovery. Changes to the CfD are beyond the scope of this workstream and so for the most part, the focus of this chapter is AI. We also discuss a number of other non-AI issues, some of these refer to charging more widely but others include the OFTO licence, the Tender Regulations and wider code changes.

Anticipatory Investment ("AI")

2.23. By its nature a significant proportion of all network investment is anticipatory. For instance, the expectation that demands on the network may change or that assets and systems may be approaching the end of their useful life will drive expenditure for an increase in capacity or a programme of renewal, either with like-for-like assets or alternative flexibility solutions.

2.24. This concept of AI is therefore not new to Ofgem. For example, within the OFTO cost assessment process, AI is one element that contributes towards the project's capex cost[16] when determining the final transfer value (we discuss this further later in the document). Within Ofgem's wider existing regulatory regimes we treat AI in different ways. RIIO-ET2, for example, distinguishes between AI and highly anticipatory investments to deal with investments of varying levels of certainty. Highly anticipatory investment might include expenditure that is not proposed or allowed either because the need for or the benefit from the investment is relatively more uncertain than would normally be the case. We have protected the consumer against the risk of stranding which increases with highly anticipatory investment.

2.25. The current framework for offshore wind development incorporates strong competition between developers, this includes the competition for seabed leases and the CfD regime. This regime has been extremely successful in helping to reduce costs and timely delivery, however it disincentivises developers to collaborate or take on extra risk. Therefore, developers have not coordinated their activities or developments to date. If two projects intend to coordinate and share assets, but one does not proceed, then the project that proceeds may have some level of increased cost as a result of the planned coordination. This puts such projects at a disadvantage for the CfD auction and increases the risk that those increased costs are not allowed as part of the cost assessment process run by Ofgem to determine the final transfer value for the OFTO assets.

2.26. Network licensees are required to develop and maintain efficient, coordinated and economic networks. However, these obligations do not apply to developers of offshore generation. In addition the uncertainties inherent in the development of offshore wind generation, taking into account coordination may mean that some AI is needed to facilitate it when projects are grouped spatially but perhaps not temporally.

Considering AI in Early Opportunities

2.27. The current regulatory framework does not prohibit AI in the OFTO or interconnector regimes – however, our policy to date has been that any AI risk has remained with the developer of a project or projects. This policy has created commercial barriers to

[16]https://www.ofgem.gov.uk/system/files/docs/2019/05/offshore_transmission_guidance_for_cost_assessment_april_2019.pdf. Paragraphs 3.60-3.65.

coordination. However, given the amount of investment likely to be needed to connect large volumes of offshore wind in future, this policy means the regulatory framework is unlikely to facilitate developers making the types of decision that will be required to ensure infrastructure is delivered in the appropriate manner in future.

2.28. Like any other costs, we assess whether AI expenditure is economic and efficient. Separate guidance explains how we do this for OFTOs and interconnectors. After we have determined the economic and efficient cost of OFTO or interconnection assets that cost is recovered from the appropriate parties, these include generators and consumers who use the electricity. The use of system charging methodology is used to allocate cost to the parties liable to pay transmission charges.

2.29. Within the current OFTO tender regime we only allow costs that are directly applicable to the specific offshore wind project subject to the tender exercise where any AI expenditure is made on behalf of the same developer. The successful bidder then purchases these assets from the developer following a tender process. When a developer makes an AI for another developer’s generation project, that is not subject to the tender we have said we would provide certainty on a case by case basis. This means there is a lack of clarity on the treatment of cost where one developer incurs cost for another.

2.30. In addition to GFAI described in the previous paragraph, in its current role of making connection offers, the ESO may already request that a developer of offshore generation includes WNBI in its project if the ESO believes this would support the economic and efficient development of the network.

2.31. We are not aware of any connection offers to date that include WNBI. However, if this is brought forward for future projects, we have previously set out that we would carry out ‘gateway assessments’ to minimise the risk of consumers bearing the cost of stranded transmission assets and to give developers comfort on their route to cost recovery for any developer-led WNBI included in their project.

2.32. Today ~80% of an OFTO’s allowed revenues are recovered from the developer that is being connected to shore, and the remainder is paid for through network charges by all network users. The precise amount paid for each generator varies based on the proportion of the transmission assets it is able to use and a number of other factors. The ESO has published a note explaining how use of system charges for offshore generators are calculated[17].

2.33. We recognise that there may be a need to change our policy to better enable and reflect an efficient level of AI in the current regulatory frameworks. Any changes in policy in relation to AI would require amendments in two areas to be given effect. These are (1) the treatment of AI within the OFTO and interconnector cost assessment guidance documents and (2) how the cost of AI is recovered through the charging regime.

2.34. Much of this section has focussed on generator focussed AI, due to the role of generators in the concepts mentioned above; however, we think we should be consistent in the treatment of AI in the OFTO and interconnector regimes. Developers will require certainty on how any AI will be treated before making a final investment decision for projects that involve coordination.

2.35. In the Early Opportunities workstream we are aiming to enable and increase coordination for projects that are already advanced, and therefore, in applying the concepts identified, all parties are known (and most are in relatively advanced stages of development). We recognise that larger and/or more complex pieces of infrastructure may be required in the future, to enable us to reach the 40GW by 2030 and Net Zero by 2050 targets. This may require different, more strategic approaches to AI. However, these require different mitigations and may require different delivery models. These are considered within the Pathway to 2030 and Enduring Regime workstreams.

AI vs highly AI

2.36. For the purposes of this workstream, we consider AI to be expenditure for a ***known future project*** (eg an offshore wind developer with a seabed lease) and there is a reasonable expectation that it will connect (albeit we will need to consider what criteria we will use to judge 'reasonable expectation'). In contrast, a highly anticipatory investment is expenditure for an ***unknown potential project or projects***.

2.37. Defining whether there is a reasonable expectation developer will connect is a challenge. There are a number of different criteria that could be used, whether a development

[17] TNUoS charging for offshore generators and the Offshore Transmission Owner regime

has a seabed lease, or an option to lease. A balance will need to be struck between being overly onerous and potentially exposing the consumer to risk it cannot control.

2.38. For the concepts and projects within the scope of this workstream, we consider there are several broad options for the funding of economic and efficient AI risk:

- AI risk could be entirely borne by the consumer; however, this may increase stranding risk and moves the risk from those able to manage it.

- Risk could be allocated either to the developer making the AI, or to the developer likely to benefit from the AI– this means risk is allocated to the organisation able to manage it; however, little to no coordination has occurred.

- Risk could be shared between the consumer and the developer or developers – there are a range of options on how to calibrate the extent to which risk is shared between the consumer and developers.

2.39. We discussed the OTNR's cross-cutting policy assessment criteria in the introduction to this document. In line with the policy assessment criterion concerning risk allocation, AI risk should be allocated to those best placed to manage it.

2.40. We are proposing that AI risk should be shared between the consumers and developers – this would be in line with the policy assessment criterion of allocating risk to those best placed to manage it while increasing the likelihood of effective coordination that benefits consumers. Ultimately this means that when the OFTO tender process is concluded rather than being paid only by the new OFTO the developer could receive funds from three sources, this is illustrated in Figure 10 below.

2.41. If we decide to implement our proposal for sharing AI as set out above, how cost recovery takes place would be subject to code modification proposals. The detail of this would need to be developed. However, instead of a single transfer of the value of the assets from the successful bidder OFTO to the developer, there may also need to be a route through which the future connecting developer pays its share of the AI to the first developer. This may be a form of user commitment for example. To the extent the consumer is paying for a share of the AI, we would need to consider how that is achieved.

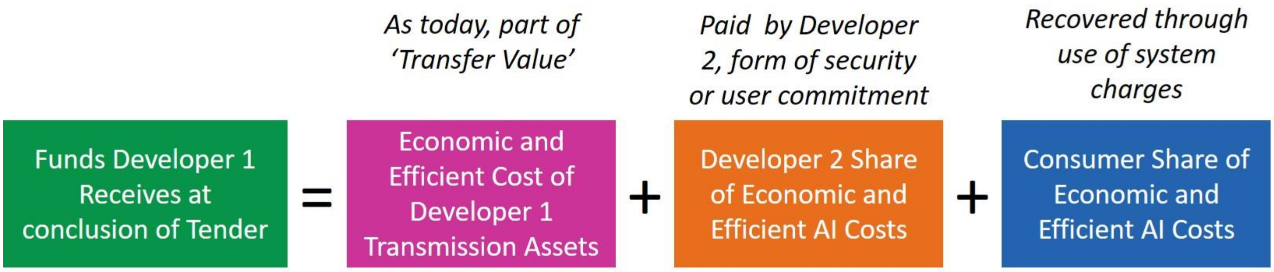


Figure 10 Illustration of the revenues the developer of the first project could receive following tender process for the concepts above

2.42. It is our view that the consumer contribution should be the minimum required to secure AI investment by developers. We are interested in stakeholders' views on this proposal, including the extent to which this risk should be shared.

2.43. In implementing this proposal, for the concepts set out in this section and for specific projects, we will need to ensure that consumers' interests are protected from the risk of inefficient AI, and that the projects intending to make use of our proposed treatment of AI are realising the benefits of coordination. As such, our general proposed treatment of AI will be subject to appropriate cost-benefit analyses and impact assessments as required. In addition, projects that fall in to the quasi bootstrap concept will require additional project specific cost benefit analyses and impact assessments. This analysis will be to assess the developers proposed option compared to the other options available, eg TO solutions.

2.44. While developing a robust framework for treating AI is important, this remains a risk mitigation tool. For each set of coordinated assets there are two scenarios - firstly, that coordinated developments proceed on the same planned timelines and there is no AI risk to

Question 2: Should anticipatory investment risk be shared with consumers? If it should, what level of risk is it appropriate for consumers to bear?

Question 3: For concepts that intended to provide a wider system benefit, e.g. by mitigating an onshore constraint, how should the need for investment be demonstrated by the developer?

Question 4: What options are available to developers in demonstrating a reasonable expectation they intend to connect to the system?

Question 5: To what extent do you agree with out proposals to remove barriers to the Early Opportunity concepts? Please explain your answer.

manage; and secondly that one or more of the coordinated developments does not proceed and AI risk needs to be allocated. This would currently be allocated entirely to the developer of the project for which expenditure was being incurred. However, as noted above, little to no AI has taken place under the current arrangements. We want our proposals to enable efficient AI and therefore to increase the coordination of offshore developments.

Changes required if we decide to implement our proposal to share AI risk

2.45. Practical implementation of the concepts outlined in paragraph 2.14 to 2.20 would likely require changes to:

- Ofgem's OFTO Cost Assessment Guidance,
- Ofgem's Interconnector Cost Assessment Guidance,
- Industry Codes and Standards, eg the Security and Quality of Supply Standard, the Grid Code etc,
- The TNUoS, and Connection Charging Methodologies outlined in the Connection and Use of System Code (CUSC), and
- Licence Conditions.

2.46. In the paragraphs below we discuss the potential amendments needed to each of these in turn.

Ofgem's Cost Assessment Guidance

Background

2.47. Ofgem's cost assessment processes ensure that only economic and efficient costs are passed onto consumers for the assets being assessed. These processes are set out in our published guidance for the OFTO and interconnector regimes, allowing developers, investors and other market participants to understand the framework through which we will assess what we consider to be economic and efficient costs.

2.48. The Offshore Transmission: Guidance for Cost Assessment[18] (the OFTO Guidance) sets out the cost assessment process that we follow to determine the final transfer value for offshore electricity transmission projects and provides developers with an overview of the information and evidence that we require. Until we determine the final transfer value, any costs incurred by a developer of offshore transmission assets are 'at risk'. The OFTO Guidance sets out how particular types of expenditure will be treated in a consistent and transparent manner (ie whether we will allow it to be included in the final transfer value or not), in order to provide as much information and assurance to developers as possible.

2.49. Our cap and floor regime is the regulated route for interconnector development in GB. The cap and floor sets a minimum and maximum return that interconnector developers can earn. At key assessment stages of the cap and floor regime, we undertake a thorough assessment of the project's costs, to ensure that only economic and efficient costs associated with the development, construction and operation of the project contribute to the project's cap and floor levels.

2.50. The Electricity Interconnectors Cost Assessment Guidance Document[19] sets out the cost assessment process that we follow whilst undertaking the cost assessments of electricity interconnectors through our cap and floor regulatory regime, and provides guidance to interconnector developers to inform submissions.

Proposed amendments to the Cost Assessment Guidance

<u>OFTO Cost Assessment</u>

2.51. We propose all economic and efficient AI for the connection of another known development to be included in the final transfer value of the offshore transmission assets at the end of the tender process (when ownership of the transmission assets required for the first generator is transferred). This is subject to amendments being made to the CUSC to ensure that AI costs are recovered appropriately, ie risk is shared through the charging methodologies between the subsequent developer (or developers) and consumers – this is discussed later in this section.

[18] Offshore Transmission: Guidance for Cost Assessment | Ofgem
[19] Electricity Interconnectors Cost Assessment Guidance Document | Ofgem

2.52. The current OFTO Cost Assessment Guidance distinguishes between single developer Generator Focused Anticipatory Investment (GFAI) and AI by one developer for another developer. We propose removing this distinction. To date we have been clear on the treatment of AI for a single developer, while we have said we will provide clarity on a case-by-case basis for multi-developer AI. We are aware that the lack of clarity on multi-developer AI could be a barrier to coordination and that the ownership of a development can change in the course of a project's development.

2.53. We recognise that there may be a benefit in providing clarity on the proposed cost assessment treatment of the early opportunity concepts. We have explained how we propose to treat these for the purposes of cost assessment within Appendix 1 of this document.

Interconnector Cost Assessment

2.54. We propose explicitly allowing all economic and efficient AI costs to contribute to the project-specific cap and floor levels (notwithstanding the conclusions of the Interconnector Policy Review regarding the future of the cap and floor regime) that are set at the Final Project Assessment (FPA) stage. It is our view that the current electricity interconnectors cost assessment guidance does not need to change to reflect this proposal.

2.55. We recognise that there may be a benefit in providing clarity on the proposed treatment of the concepts that include interconnectors. We have therefore explained how we propose to treat these for the purposes of cost assessment within Appendix 1 of this document.

Industry Codes and Standards

Background

2.56. The industry codes underpin both the electricity and gas markets. Licensees are required to maintain, become party to, or comply with the industry codes in accordance with the conditions of their licence.

2.57. The Balancing and Settlement Code (BSC) contains the governance arrangements for electricity balancing and settlement in Great Britain. The Connection and Use of System Code (CUSC) constitutes the contractual framework for connection to, and use of, the national electricity transmission system (NETS). The Grid Code covers all material technical aspects relating to connections to, and the operation and use of, the NETS. The System Operator –

Transmission Owner Code (STC) defines the high-level relationship between the ESO and onshore and offshore transmission owners.

2.58. In addition to the core industry codes listed above, the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) sets out the minimum standards for the planning and operation of the NETS, which consists of infrastructure owned or operated by transmission licensees.

2.59. The code governance processes allow industry to develop and assess modifications through consultation and working groups, and for the relevant code panel to vote on the change. Ofgem's role is to assess proposals according to the objectives set out in the code frameworks and our principal and statutory duties, in order to reach a decision on whether to approve or reject modification proposals.

2.60. In instances where a code modification may not be proportionate to overcoming a particular barrier, a licensee may submit a request to Ofgem for a derogation from the licence requirement to comply with a technical standard or code, in specified circumstances and to a specified extent. If we are satisfied that the information received meets the minimum requirements and consider that the derogation request is justified, then we will issue a derogation to the affected party granting the necessary relief.

Overcoming barriers to enable Early Opportunities

2.61. We expect this workstream will have a more significant impact on some of the codes and standards than on others, including the CUSC, SQSS and Grid Code. For example, changes would be required to the CUSC to facilitate appropriate risk sharing between developers and consumers for AI.

2.62. We also expect Grid Code development will be required to address the treatment of connections to, and the operation and use of, more integrated offshore network designs, including designs which may combine elements that are otherwise treated distinctly, such as an offshore generator and an interconnector.

Our expectations on who is best placed to raise modification proposals

2.63. Given the incremental nature of the changes we envisage under this workstream, we expect the industry-led governance processes set out in the respective codes to be used for the necessary code modifications or derogations. We do not believe that a Significant Code

Review ("SCR") is required for Early Opportunities, as SCRs are usually focused on more fundamental or wholesale changes to codes. We expect the changes required here to be more limited or more regular in nature. However, we invite stakeholders to provide their view on this.

2.64. We think industry and the ESO are best placed to develop and propose modifications in the context of this workstream. The novel network infrastructure that is proposed as a result of this workstream has been conceptualised by developers of offshore wind farms and interconnectors. Developers are working with the ESO to understand where the detailed barriers exist in codes and standards and consequentially where modifications are likely to be required. Individual developers, working with the ESO, have the best view of what is required to facilitate individual concepts. As the ESO is engaged with all the developers who have identified opportunities for coordination, we consider that the ESO likely has the best view of changes required to facilitate the suite of concepts.

2.65. If we decide to implement our proposal in paragraph 2.40 to share AI risk, we expect the ESO will take the lead in developing and proposing charging related code modifications. For other amendments to industry codes and standards we expect developers and the ESO to continue their ongoing collaboration and that the appropriate party raises a modification. This may mean where a modification is more applicable to one concept the developer proposes the modification, but where it covers a number of concepts the ESO raises the modification. This should mean that modifications are proposed in a coordinated manner and avoid duplication or competing modifications.

2.66. As noted above, where industry parties believe that a code modification may – following review – be a disproportionate approach to overcoming a particular barrier, a licensee may submit a request for a derogation.

Connection and Use of System Code & wider charging arrangements

Background

2.67. Users of the transmission system are subject to three types of transmission charges: Connection Charges, Transmission Network Use of System (TNUoS) charges, and Balancing Services Use of System (BSUoS) charges. Section 14 of the Connection and Use of System Code (CUSC) sets out the methodologies by which each of these charges is calculated.

2.68. Connection Charges recover the cost of the assets installed solely for, and generally only capable of use by, an individual user connecting to the transmission network. TNUoS charges recover the cost of providing and maintaining assets which may be used by more than one User, and are split between Local Charges (charges relating to specific assets used by a generator to connect to the broader system) and Wider Charges (charges for infrastructure). Under today's arrangements, these transmission charges allow onshore and offshore transmission owners to recover the costs of building owning and maintaining transmission assets.

2.69. The TNUoS paid by an offshore generator is made up of three elements. These are (1) the offshore substation tariff, (2) the offshore circuit tariff related to the cost of the of OFTO circuit, and (3) the wider tariff associated with the use of the Main Integrated Transmission System. Our proposals in this chapter relate primarily to elements (1) and (2). The ESO has published a Guide to TNUoS Charging Methodology for Offshore Generation in GB[20].

Our proposals regarding how to make code changes

2.70. While the OFTO and Interconnector Cost Assessment guidance documents explain how we assess costs, the use of system charging methodologies explain how charges are derived. This means that changes must also be made to the charging methodologies if the risk of AI is to be shared appropriately between consumers and the developers of offshore infrastructure.

2.71. We expect that changes to the charging methodologies to facilitate the early opportunities concepts will be made through the industry-led governance processes, informed by the overall objective of the OTNR. We will engage with industry parties (and subsequent workgroups) that bring forward relevant code modifications.

2.72. As with all of Ofgem's regulatory decisions, in assessing charging reforms we are guided by our principal objective and statutory duties. Our principal objective is to protect the interests of existing and future consumers, where the interests of consumers are their interests taken as a whole, including their interests in advancing decarbonisation and in the security of the supply of gas and electricity to them[21].

[20] 44938-Offshore Information.pdf (nationalgrid.com)
[21] Our powers and duties | Ofgem

2.73. Absent a SCR, through which we can develop specific principles (with reference to our principal objective and statutory duties), our principles will also be informed by the objectives in relevant codes. The applicable CUSC charging objectives stress the importance of cost-reflectivity, facilitating effective competition, reflecting developments in transmission businesses, compliance with relevant European regulation, and implementation and administrative efficiency.

2.74. We consider that any proposed modifications the CUSC should be informed by a number of desirable features. We have described these below in Figure 11.

Desirable features of charging arrangements

We think that there are a number of desirable features for offshore charging arrangements that, if met, will help achieve the OTNR's objective with respect to the identified Early Opportunities. This list is by no means exhaustive, but desirable features that proposed CUSC modifications seek to achieve may include:

1. **Arrangements should provide for appropriate allocation of risks when developing network capacity.**

- This could include some level of shared risk between developers and between developers and consumers. Where there is a clear system benefit and development case for AI, then it may not be appropriate for its risk to be entirely borne by the developer.
- We would expect any risk that is shared between a developer or developers and consumers to be proportionate to the benefits that developers might receive if and when they do connect to the system – we would expect the proportion of costs to be shared to developed as part of the code modification process. We expect the support provided from the consumer to be the minimum required to secure developer investment.

2. **Future offshore connection scenarios identified through the concepts should be definable and have a centralised, Ofgem-approved and transparent charging methodology.**

3. **Arrangements should support competition by enabling a level playing field across different types of users and offshore connection arrangements.** As far as is practicable, the same obligations, revenue opportunities, and access rights should apply to equivalent current and future offshore generation connections to promote effective competition. The approach to ensuring that the eventual OFTO receives their tender revenue stream should be consistent across all offshore connections.

4. **Network users should face cost-reflective charges for network access and/or usage, ie their costs reflect the cost of the offshore infrastructure assets that they can or do use, based on the extent to which they can use them (capacity) or the extent to which those assets can deliver a wider system benefit.** For example, this feature should apply in scenarios where what would normally fall to be defined as offshore transmission infrastructure is mitigating an onshore constraint.

Figure 11 Desirable charging features for potential CUSC modifications proposals

Other issues to be addressed for Early Opportunities Concepts

Non-AI charging issues

2.75. The six concepts identified raise a number of wider charging questions. While the concepts may raise new questions there are existing treatments for these costs within the existing codes and standards. The table below sets out our initial view of charging arrangements to be considered when recovering the costs of coordinated infrastructure in the context of the specific concepts. These points go wider than simply the treatment of AI to cover other aspects of charging.

Table 1 Other considerations when developing charging modification proposals

Concept	Our initial view of charging arrangements to be considered in cost recovery
Shared offshore transmission system	The current charging arrangements for generation and demand users would continue, subject to any in-flight code modifications or other areas of review.
Connection of electricity storage or a demand user to an offshore transmission system	
A circuit which connects two (or more) offshore substations that are not connected to a single common substation	Offshore generators would continue to face wider locational transmission charges and local transmission generator charges, which recover the cost of the parts of the network that link individual user connections to the MITS.
Connection of an offshore generator to infrastructure that is located offshore and	

owned by a Transmission Owner (TO)	
Multi-purpose interconnector (interconnector-led model)	The current charging for interconnectors would apply to an interconnector if that interconnector forms part of an MPI. This feature would be applied if the interconnector element forms part of an MPI from inception, or if an existing interconnector becomes part of an MPI. Therefore, interconnectors whether part of an MPI or not would not be subject to TNUoS charges or BSUoS charges.
Multi-purpose interconnector (OFTO-led model)	An interconnector accessing the MITS via an offshore transmission system would be subject to the existing charging and access arrangements. This means that the interconnector element would not be subject to TNUoS charges or BSUoS charges. The current charging arrangements for the use of an offshore transmission system by an offshore generator would continue if the offshore transmission system forms part of an MPI from inception, or if an existing offshore transmission system becomes part of an MPI.

Tender Regulations & Licence Conditions

2.76. OFTO licences are granted on the basis of a competitive tender process which is managed by Ofgem. The Electricity Act 1989 allows Ofgem to make regulations for competitive tenders for offshore licences. The regulations are subject to approval by the Secretary of State and underpin the competitive tender process used to grant offshore transmission licences.

2.77. Following the competitive tender process within the OFTO Tender Regime we award an OFTO licence. In addition, interconnection is a licensable activity. The OFTO Licence and the Interconnector Licence place rules on how licensees can operate within their licences. They also set out how much revenue licensees can recover in some cases.

Proposals to overcome other issues

2.78. We do not consider that the broad regulatory framework given effect to in the licence is a barrier to the concepts above. However, we consider that mechanics set out in the licence need to be reviewed and drafting amended in certain areas.

2.79. We do not believe the principles given effect to by the Tender Regulations are a barrier to the implementation of Early Opportunities but some of the mechanisms therein may be. However, we note that to implement our AI proposal there may be consequential changes we need to make to the Tender Regulations and we will consider these this year.

2.80. We propose applying the policy set out in the Generic TR6 OFTO licence[22] to the concepts. We propose developing draft Amended Standard Conditions where it is necessary in the course of this year. This may mean changes to how, for example, the Availability Incentive is given effect to within the licence, but we do not intend to substantively change the effect of the incentive itself. We will engage with specific developers to understand when amendments to licence drafting for particular concepts might be required.

2.81. We expect that changes to the Tender Regulations could be required to accommodate Early Opportunities. Ofgem will amend the Tender Regulations as and when it is necessary to do so with further consultation as required.

Question 6: Do you believe a Significant Code Review is required to give effect to a potential decision to 'share' AI risk between consumers and developers?

Question 7: Do you agree with Ofgem's proposed approach to deliver the objectives of Early Opportunities workstream?

Next Steps

2.82. Following this consultation, engagement with stakeholders, and further analysis, we intend to make a decision on proposals this year. We will then consult stakeholders on the changes required to the framework that will facilitate implementation, for example licence conditions and Cost Assessment Guidance.

2.83. In respect of charging and code modifications, if following consultation we decide to implement our risk sharing proposals, we expect the ESO will take the lead in developing and proposing charging related code modifications. For other amendments to industry codes and standards we expect developers and the ESO to continue their ongoing collaboration and for

[22] Offshore Transmission: Generic OFTO Licence and Guidance for TR6 | Ofgem

the appropriate parties to propose the necessary modifications if a modification is more applicable to one concept than others, then the developer would proposes the modification, but if it covers a number of concepts then the ESO would raises the modification. This should mean that modifications are proposed in a coordinated manner and avoid duplication or competing modifications.

2.84. If required, we will undertake any necessary Impact Assessments and would publish that alongside any decision documents on Early Opportunities.

Summary of Early Opportunities questions

Question 1: Are there any concepts we have not identified developers may wish to progress?

Question 2: Should anticipatory investment risk be shared with consumers? If it should, what level of risk is it appropriate for consumers to bear?

Question 3: For concepts that intended to provide a wider system benefit, e.g. by mitigating an onshore constraint, how should the need for investment be demonstrated by the developer?

Question 4: What options are available to developers in demonstrating a reasonable expectation they intend to connect to the system?

Question 5: To what extent do you agree with out proposals to remove barriers to the Early Opportunity concepts? Please explain your answer.

Question 6: Do you believe a Significant Code Review is required to give effect to a potential decision to 'share' AI risk between consumers and developers?

Question 7: Do you agree with Ofgem's proposed approach to deliver the objectives of Early Opportunities workstream?

3. Pathway to 2030

Section summary

This chapter sets out the proposed approach for a holistic onshore and offshore network design to enable coordination in the delivery of the 40GW by 2030 target[23]; we are specifically seeking to capture the current ScotWind and Crown Estate Leasing Round (LR4) projects. We discuss three areas of work, the development of a generation map, how we intend the network to be designed and the delivery options for the required network infrastructure.

Introduction

Objective and scope of Pathway to 2030

3.1. This workstream sits between the Early Opportunities and Enduring workstreams in terms of the projects upon which it will have an impact. Pathway to 2030 was established as it was recognised that the short-term, Early Opportunities workstream might not be sufficiently impactful while the long-term, Enduring Regime may not be sufficiently timely. Government has set a target of 40GW by 2030 and there are potentially substantial benefits to be gained from coordination in this medium-term period. This is illustrated in Table 2. This forecasted generation and the findings of National Grid Electricity System Operator's report[24] on offshore coordination illustrate the benefits of taking action rather than continuing with the status quo.

[23] https://www.gov.uk/government/news/new-plans-to-make-uk-world-leader-in-green-energy
[24] The final Phase 1 report in our Offshore Coordination project | National Grid ESO

Table 2 Offshore wind generation pipeline

Current Stage:	Operational	Pre-Construction	Seeking Contract for Difference Allocation Round 4	Seeking Consents	Seeking Seabed Lease	Future Projects
Operational by:	Now	2023-25	2025-27	2027-30	2030+	2030-2050
Capacity:	10.4GW	9.1GW	~12.5GW	~7.2GW	~19GW	~42GW
Cumulative:	10.4GW	19.5GW	~32GW	~39.2GW	~58.2GW	~100GW

3.2. It can take up to ten years (and in many cases longer) for a project to move from securing an option to lease seabed to commercial operation. The closer to commercial operation a project is, the more difficult it is to make substantive changes to the project to enable more coordination with other projects. This means that the Early Opportunities workstream will focus on facilitating changes developers are able and willing to make to projects at an advanced stage of development. However, it is possible to contemplate far more ambition for those projects that are at an earlier stage in their development. Because Pathway to 2030 is looking at those projects for which an option to lease has just been secured or will shortly be secured (in the case of ScotWind), we have a window in which more can be done to facilitate greater coordination.

3.3. The objective of this workstream is to drive the coordination of offshore projects progressing through Crown Estate (TCE) Leasing Round 4 (LR4) and Crown Estate Scotland (CES) ScotWind connecting to the transmission system by 2030. Projects from LR4 and ScotWind will help put the UK on track to meet the government target for 40GW of offshore wind capacity by 2030 as well as contributing to the Sixth Carbon Budget[25]. LR4 creates the opportunity for at least 7GW of new offshore wind projects in the waters around England and Wales by the end of the decade and Crown Estate Scotland is offering 10GW of seabed leasing. It is also anticipated that projects from earlier leasing rounds with a connection date in the late 2020s or early 2030s could be incorporated in to this workstream. Our aim is to find effective solutions to ensure that the national electricity transmission system both onshore and offshore is planned and built in a more coordinated way. Our proposals are

[25] Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)

intended to minimise the environmental and local community impact of the new infrastructure that will be required.

3.4. Within the scope of this workstream we are considering moving substantively away from the existing model for the design and delivery of certain asset types. We think that at a high level the onshore and offshore elements of the transmission system should be considered holistically so that efficiencies can be secured. Further, we think there could be changes to how offshore infrastructure is delivered if it is designed holistically. This workstream could result in the biggest change to date in how offshore transmission infrastructure is developed since the sector was established – this applies to both how assets are designed and how they are delivered. The workstream has three work areas. These are:

- The development of a generation map showing where offshore wind projects (in particular projects from LR4 and Scotwind) are expected to be sited are expected to be sited and when they are expected to connect to the system.

- The production of a design for network infrastructure which is based on the generation map and other relevant information – this design work should also include work detailing where changes might be required to industry codes.

- Based on the proposed network infrastructure, options for the efficient delivery of the coordinated infrastructure required to connect offshore generation.

3.5. As noted above, given the stage of development of projects that are within the scope of Pathways to 2030, there is a reasonably small window within which we can effect change. We recognise that affected parties may be concerned that this workstream will lead to uncertainty and potential delays in project timelines if there is a move to a more centrally planned network. While planned reforms may result in delays in the early development steps, we envisage the new approach will speed up later development steps, including the consenting process, thus reducing the overall time for project delivery.

3.6. This chapter describes our work on Pathway to 2030 to date – but it seeks stakeholder views only on elements of the 'network design' and 'delivery of offshore' assets aspects of the work. We explain why this the case at relevant points throughout the chapter.

3.7. As explained below, we recognise that the design work could result in radial links to shore being retained where it is appropriate. Where this is the case, we would expect one of the two existing delivery models to be adopted. Developers may choose to either develop and construct the Transmission Assets themselves and then transfer the completed Transmission Assets to the OFTO identified through the Tender Exercise (the Generator Build option) or undertake high-level design and preliminary works, but then defer the detailed design, procurement and delivery of the Transmission Assets to the OFTO (the OFTO Build option). This means that radial links would be out of the scope of the delivery models discussed later in this chapter.

Our work so far

3.8. Significant work has already been undertaken by Ofgem, BEIS, ESO, TCE, CES, and transmission owners (TOs) on the generation map and the network design terms of reference. More information on these is provided below but we do not seek views on either of these areas.

Approach to consultation

3.9. We are consulting on different models for the delivery of the infrastructure and have set out our view on all the reasonable options. Rather than set out a preference as the starting point for consultation, we are seeking views on all options presented. Following feedback from this consultation on the options, we will decide on a preferred delivery model and consult further on the detail of how it will be implemented.

Generation Map

3.10. The Generation Map illustrates a potential temporal development pathway for offshore wind projects in GB over the next decade up to and including preferred projects identified through The Crown Estate's Leasing Round 4 (LR4) process, using publicly available data. It is intended to support network planners and infrastructure investment decision-makers by combining information on the location of offshore wind projects with information on planned connection dates where this is available. It also shows a broader spatial context for development by including the onshore transmission system, offshore cable routes (where known), other offshore assets such as aggregates production areas and CCS sites, and environmental data. It will supplement other data sources such as the Future Energy

Scenarios[26](FES), the Network Options Assessment[27](NOA) and the Electricity Ten Year Statement[28](ETYS), rather than replace them.

3.11. The data for Scotland does not yet include the outcome of ScotWind Leasing. The ScotWind Leasing application window closes on 16 July 2021, and the process is due to conclude in early 2022. The ScotWind process has already resulted in over 50GW of connection requests. Up to 8,600 km^2 of seabed will be made available through ScotWind Leasing to support the development of projects capable of delivering up to 10GW of total generating capacity. The TOs and the ESO will ensure that the data relating to ScotWind that informs the network design is robust and representative of what generation is reasonably expected to connect, and when the ScotWind leasing round is complete, the leasing round outcomes will be incorporated in the HND.

3.12. The Generation Map has been developed by TCE following substantial engagement between BEIS, Ofgem, ESO, TCE, CES and TOs. It will provide planners and Ofgem with increased specificity in spatial and temporal terms.

3.13. A more coordinated or integrated transmission system is likely to involve increased levels of anticipatory investment (AI). This has the potential to increase the risk of asset stranding. By providing more granular data than is contained within existing models, and spatial data within a single information source we think the generation map will help to mitigate this risk. The generation map will show where the offshore generation pipeline to 2030 and beyond is currently intended to be sited, and when it is expected to connect. It is important to note that the map will not indicate a decision about the siting of future generation. It will only illustrate previous decisions which have already been made.

3.14. The generation map has been compiled using data from a number of publicly available sources including:

- The Crown Estate’s Open Data Portal
- Crown Estate Scotland Open Data

[26] Future Energy Scenarios | National Grid ESO
[27] Network Options Assessment (NOA) | National Grid ESO
[28] Electricity Ten Year Statement (ETYS) | National Grid ESO

- The ESO's generation Transmission Entry Capacity (TEC) Register[29]
- Marine Scotland Sectoral Marine Plans
- The Joint Nature Conservation Committee
- Natural England
- Natural Resources Wales, and
- Scottish Natural Heritage

3.15. Upon the completion of TCE's work, the map will be provided to the ESO, the TOs, Ofgem and BEIS. It will be in a format in which those organisations will be able to access the data and add other data sources to inform the work of each organisation whether that be the delivery of infrastructure or network regulation. We have been clear that when using the map to support proposals by TOs, it must be possible to distinguish between data provided by TCE/CES and data developed from other sources.

Network Design

Network Design Terms of Reference

3.16. One of the objectives of the Pathway to 2030 workstream is to ensure that all network infrastructure (both onshore and offshore) which is necessary to connect projects in scope of this workstream is designed in a coordinated manner with an optimum engineering solution that at the same time considers the economic, environmental and community impacts. We think there are three elements of network design required to deliver this objective – a holistic network design (HND), and detailed designs (DNDs) for each of the onshore and offshore network assets.

3.17. We explain below that the HND will be delivered by ESO. The DND for onshore assets will be delivered by the TOs. We are not asking questions on the roles and responsibilities of the TOs in this regard. However, we do seek views later in this on who might be best to deliver the DND for offshore assets.

3.18. We are finalising Terms of Reference (ToR) with BEIS, the TOs and the ESO which set the scope of the parties involved in delivering the HND (ESO) and DND (TOs onshore and to

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[29] ESO Data Portal: Transmission Entry Capacity (TEC) Register - Dataset| National Grid Electricity System Operator (nationalgrideso.com)

be confirmed for offshore). The ToR (see Appendix 2) do not change or replace the existing legislative or regulatory obligations which TOs must take into consideration when developing infrastructure. The ToR set out the requirements for the HND and DND, and they also set out the roles and responsibilities of different parties. This includes the expectation that the HND will be informed by consultation with stakeholders. The ToR are intended as an additional reference point so that licensees clearly understand the objectives of the OTNR within this work area.

3.19. In order to ensure the OTNR objective[30] is embedded in the design work, BEIS and Ofgem have included a number of objectives for licensees to consider when developing designs. These include the impact on the environment and local communities.

Table 3 Network Design Objectives

#	Name	Description
1	Economic and efficient costs	Network solution is economic and efficient
2	Deliverability and operability	Network solution is deliverable by 2030 and the resulting system is safe, reliable and operable
3	Environmental impact	Environmental impacts are avoided, minimised or mitigated by the network design and best practice in environmental management is incorporated in the network design
4	Local communities impact	Local communities impacts are avoided, minimised or mitigated by the network design

3.20. The ToR distinguishes between the HND and DND. We are not seeking views on the ToR, as it is not intended to change any of the obligations on parties. It is intended to remind licensees of the issues which they should be considering and ensure there is effective working between different parties.

[30] The OTNR’s objective is to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, considering the increased ambition for offshore wind to achieve net zero. This will be done with a view to finding the appropriate balance between environmental, social and economic costs.

3.21. We do seek views later in this document on who might be best placed to design and deliver offshore assets.

Holistic Network Design (HND)

3.22. In thinking about who is best placed to lead the development and delivery of the HND, we have identified the ESO as the most appropriate party given its current roles (including the NOA[31]). BEIS will seek views in its later consultation on the role of the ESO within the Enduring Regime workstream. BEIS are considering Ofgem's SO Review assessment and recommendations, and we are working closely with them to consider SO roles, functions and design within the wider context of the Future System Operator work[32].

3.23. Given the interaction between the ESO and the TOs and the need for collaboration to deliver the Network Design, a central design group (CDG) has been formed so this engagement can take place. The CDG are expected to consult with local communities and developers in progressing the HND as well as other relevant stakeholders and may invite these parties to attend the CDG as appropriate. The ToR referenced above in paragraph 3.18 governs its work. The HND will identify the requirements for network capacity on the national electricity transmission system (NETS) across GB onshore and in offshore waters to efficiently connect projects within the scope of this workstream (see paragraph 3.3 for more details on scope). The ESO and the TOs will consider the extent to which the HND should include other specifications in addition to capacity requirements, eg indications on the location of infrastructure such as proposed cable corridors and new substations, recommended technology etc.

3.24. The HND should provide a sufficient level of detail to allow the parties undertaking the detailed network design (DND – see paragraph 3.28 for more details) to make decisions about the specific assets that would fulfil the requirements of the HND.

3.25. The delineation between onshore and offshore assets will be established following completion of the HND. For assets which are point-to-point connections, it is intended that these will be classified as offshore assets. For connections other than radial connections, a

[31] Network Options Assessment (NOA) | National Grid ESO
[32] Ongoing work to consider the future role of the system operator follows Ofgem's review of GB energy system operation: Review of GB energy system operation | Ofgem

classification decision will have to be made to determine whether to apply the onshore or offshore licensing regime.

3.26. All licensees will need to consider interactions with other regulatory processes and the HND should be developed with robust procedures and benefit cases. For example, it should include a robust cost benefit analysis of the different options available. We expect the HND to be delivered according to a robust methodology cognisant of, and consistent with, the requirements of the RIIO processes. If the evidence that supports the HND is of an equivalent standard to that which is required to support submissions for price control reopeners, this should reduce the additional work required by TOs and Ofgem if and when a reopener is triggered.

3.27. The ToR make clear that while the ESO will be the party responsible for delivering the HND, the ESO should work closely with the TOs as they will be responsible for developing the DND onshore.

Question 8: We consider that a holistic design will result in a more coordinated, economic and efficient network. Do you agree? Please give reasons for your answer.

Detailed Network Design (DND)

3.28. This DND phase is the process through which the design for network assets (please see the draft ToRs for how network assets are defined in this context) is established to the next level of detail based on the requirements for the HND. The DND should also seek to address key environmental and cumulative impacts indicated in the HND and include mitigations, as appropriate.

Detailed Network Design (DND) Onshore

3.29. The DND Onshore will be developed by the TOs. This is not a new role for the TOs. It is, however, an evolution of their existing roles in that they will be considering the onshore/offshore interface to a greater degree than has been the case to date. The TOs will be responsible for the DND Onshore in their respective licence areas.

3.30. The DND should be at a level of detail that allows TOs, or other delivery parties (if Ofgem decides to apply a model of onshore competition to that infrastructure), to proceed with the delivery of Network Assets, such as the pre-consenting development phase and detailed technical studies. Where the TO is progressing development of the infrastructure the DND should be at a level of detail that allows the TO to make a submission to the appropriate RIIO-T2 uncertainty mechanisms (eg Large Onshore Transmission Investments (LOTI) reopener) if appropriate. It should also provide an early indication of when the LOTI reopener mechanism could be triggered.

3.31. As with the HND, we would note that the more robust the processes that inform the DND, the less interrogation is likely to be required during any reopener processes.

Detailed Network Design (DND) Offshore

3.32. We have yet to decide who will undertake the DND Offshore. This question relates to who will deliver the infrastructure offshore and what delivery model is adopted. This is discussed in the remainder of this section. We welcome the views of stakeholders on who they consider is best placed to undertake the DND Offshore and which delivery model should be adopted.

3.33. Like the DND Onshore, the DND Offshore should be at a level of detail that allows licensees or bidders to proceed with delivery of network assets, such as pre-consenting and detailed technical studies.

Question 9: Do you agree with the planned work for a detailed network design offshore? Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

Question 10: Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

Delivery

Delivery Onshore

3.34. The delivery of onshore infrastructure is not the subject of this consultation. This infrastructure will be delivered by the incumbent TOs under their existing price controls, unless Ofgem decides to apply a model of onshore competition to that infrastructure.

However, we would expect that where a robust methodology is applied in the development of the HND and later the DND Onshore, then less interrogation will be required of submissions.

Delivery Offshore

3.35. Where the HND indicates that a radial connection would be the most economic and efficient solution for an offshore generator, we propose continuing to use the delivery model set out in existing OFTO Tender Regime, via either the OFTO or generator build routes. The existing developer led model is well known and works well for radial infrastructure. We do not think there is a need to change it, subject to requiring developers to build infrastructure in line with the HND.

3.36. Where the HND indicates something other than a radial solution, we propose using one of the six delivery models further discussed in this consultation in paragraphs 3.46 to 3.63. Common across five of the six models outlined is an element of competition. Our thinking on implementation of competitive processes is outlined in paragraphs 3.37 to 3.45 to provide context for our consideration of the various options which follows.

Why we use competition

3.37. Promoting competition can help deliver better outcomes for consumers, driving cost efficiencies in key areas. It also has a key role to play in driving innovative solutions and efficient delivery that can help meet Government's decarbonisation targets at the lowest possible cost. In making our decision on which delivery model to select, we continue to be of the view that competition should be retained where it is practicable and in the interests of consumers to do so.

3.38. Competition in the design and delivery of energy networks is important in facilitating the efficient and cost-effective delivery of infrastructure. For onshore infrastructure, it is a central aspect of the RIIO-2 price controls. Under the existing OFTO regime, competition in the delivery of offshore electricity transmission infrastructure has driven significant savings. This has been a model for how competition for the market can be used to deliver benefits for bill payers. Under the current OFTO regime, Ofgem runs a competitive tender process to select and licence OFTOs to finance and operate the transmission assets. It is estimated that the combined savings from Tender Rounds 1, 2 and 3 are between £628m and £1.149bn[33]. In addition, the OFTO tender regime has provided other benefits – such as providing market information that can be used in other regimes. We have used information gathered in the course of OFTO tender processes to assess the capital costs for interconnector, strategic wider works and (LOTI) projects. Our analysis of the equity returns required by investors in the OFTO regime contributed to shaping our recent RIIO-2 cost of capital proposals.

3.39. With this, and the OTNR Policy Assessment criteria in mind, all bar one of the potential delivery models considered in this consultation has a role for competition. We intend to undertake an impact assessment before deciding on a preferred model.

Types of competition based on when competition is run

3.40. There are a range of competitive models available. The models vary depending on the point in the project development timeline at which the competitive process is run (from very early to very late) and which party develops the project before the competition. Figure 12 (first used in our RIIO-2 Sector Specific Methodology consultation) illustrates how we categorise competition models by the point in a project's development at which a competition is held.

3.41. Appendix 2 of our RIIO-2 Sector Specific Methodology consultation core document explains the advantages of different early and late competition models[34].

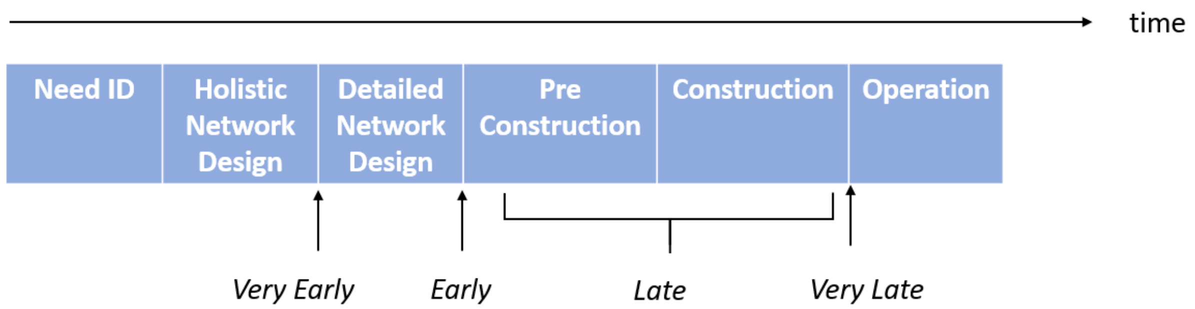

Figure 12 Typical project process and types of competition

[33] TR7 Generic Preliminary Information Memorandum (ofgem.gov.uk)
[34] RIIO-2 sector specific methodology consultation | Ofgem

Early Competition

3.42. Early competitions are run in the formative stages of a project's development timeline.

3.43. Early competitions can generate benefits to consumers by encouraging innovation in solving network problems. This could potentially lead to significant capital cost savings, for example where a different technology or different route are used. There are however potential drawbacks. When the competition is run early on in the project development process, information about the project is less clear, more uncertain (eg land surveys or environmental assessment outcomes) and so it is not likely to be efficient to ask bidders to bid fixed costs for delivering, financing and operating their proposed solution. Change control mechanisms (eg cost assessments or debt funding competitions), potentially including cost cap limitations, are therefore required in order to mitigate this uncertainty. Furthermore, the earlier a process is run, the greater the likelihood of changes in circumstances which might mean a different solution may become more appropriate, or the need for a project may drop away entirely. We note that, in this context, the generation map and HND are intended to mitigate (to at least some extent) this risk.

Late Competition

3.44. Under late competition models, the competition typically commences towards the end of the project development lifecycle, when the detailed network design has been determined and planning consents have been obtained. This means that there is less scope for the benefits that might be delivered by innovation in design. There is, however, greater certainty with a late competition model on what the final project looks like and requires, since detailed design and major planning consents will be in place prior to the time at which the competition is run. The primary benefit of the competition is therefore around additional efficiency in construction delivery, financing, operation and maintenance of network assets (depending on the exact timing of the competition). The generator-build model under the existing OFTO Tender regime is an example of a 'very late competition', where the asset has already been constructed and the competition therefore focuses only on financing and operation and maintenance.

Which party develops the project before the competition

3.45. As set out in paragraph 3.36, competition models can also vary based on which party develops the project before the competition. We have considered models where either the onshore TO, the ESO, or an offshore generator, carries out these works before the competition. The later the competition, the greater the extent of these works, which requires different obligations, incentives, and cost allowances, as well as different skillsets.

Delivery models

3.46. In line with the above, we are considering the following delivery models for offshore infrastructure, of which models 2 to 6 all incorporate competition for the market (ie competition to determine the OFTO) – this is indicated by the purple line. Our timelines for implementation will depend on the detail of the models chosen. We will therefore set out more information on our proposed next steps in our decision and further consultation on the next level of detail.

Table 4 Delivery models

Delivery Model	Holistic Network Design	Detailed Network Design	Pre-Construction (eg Consenting)	Construction	Operation
1. TO Build and Operate	ESO	TO	TO	TO	TO
2. TO Build > OFTO Operate	ESO	TO	TO	TO	OFTO
3. TO Design > OFTO Build and Operate	ESO	TO	TO	OFTO	OFTO
4. Early OFTO Competition	ESO	ESO ***or*** TO	OFTO	OFTO	OFTO
5. Very Early OFTO Competition >	ESO	OFTO	OFTO	OFTO	OFTO
6. Developer design and build, OFTO operate	ESO	Offshore generator	Offshore generator	Offshore generator	OFTO

Option 1 – TO Build and Operate

3.47. This model requires the incumbent TO to undertake the Detailed Network Design (DND), develop, construct and operate all shared infrastructure in their existing licence area, which includes the Renewable Energy Zone[35].

3.48. A strength of this model is that infrastructure and delivery can be coordinated easily as the same parties will be responsible for the whole chain of development. This could potentially (but not necessarily) increase the speed at which infrastructure could be taken from the design and delivery stage when compared to some of the other models. Speed of delivery is a key factor considering the desire to facilitate the Government's objective of connecting 40GW of wind by 2030.

3.49. There are however a number of challenges to using this option. The legislative basis on which this could be achieved would require further review, including consideration of how these assets are categorised (eg whether they would constitute offshore transmission assets or reinforcement of the onshore system) and how they would be licensed for operation. Further, this option does not include a role for competition beyond that inherent in the TO's procurement processes. This limits the possibility of achieving cost savings for consumers.

3.50. It should also be noted that we recently concluded the RIIO-2 price control review with the price control period beginning on 1 April 2021. No consideration was given to the TO having a wider role in the delivery or operation of 'infrastructure necessary for offshore transmission' – this was not within the scope of the price control review. However, there are mechanisms available to both the TOs and Ofgem to manage uncertainty, eg, the Large Onshore Transmission Investment (LOTI) and Net Zero Reopener (NZR) mechanisms.

Option 2 – TO Build > OFTO Operate

3.51. As with Option 1, this option requires the incumbent TO to undertake DND, develop and construct the shared infrastructure but would see an OFTO in place for the operational phase. Under this option, at or near asset completion, a tender process would be run to

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[35] An area of sea outside the UK territorial sea over which the UK claims exclusive rights for production of energy from water and wind under section 84 of the Energy Act 2004. The boundaries of the REZ have been redefined so that they are largely consistent with the Exclusive Economic Zone (EEZ).

transfer ownership of the assets built by the TO to the OFTO. This would be a tender process similar to that run under the present regime (under the generator-build model) and is an example of a very late competition model.

3.52. This model retains the benefits of permitting coordinated delivery and increased speed of delivery, key factors in facilitating the Government's objectives to 2030. In contrast to Option 1, Option 2 does include a competitive element, albeit the 'very late' competition model with the smaller scope for competition which that entails.

3.53. If this model is adopted, consideration will need to be given to the appropriate transfer value of any offshore transmission assets. Under the current arrangements we determine the economic and efficient costs of infrastructure and this becomes the transfer value of the offshore transmission system. Prospective OFTOs then compete on various elements, in particular the cost of capital and the operation and maintenance (O&M) costs. Under this option we would need to consider how to efficiently profile the TO's allowances within its regulated asset base in the RIIO framework before and after the transfer of assets to an OFTO. This may be complex. We would also need to carefully consider the appropriate incentives and outputs to set in TOs' licences in order to ensure efficient delivery of the assets to be transferred to the OFTO.

Option 3 – TO Design > OFTO Build and Operate

3.54. This model would require the ESO to undertake the HND, the incumbent TO to undertake the detailed design and consent the shared infrastructure, with the subsequent appointment of an OFTO to construct and operate it. This is an example of a late competition model.

3.55. As with Options 1 and 2 above, this option shares the benefit of coordination of design. However, responsibility for construction of the assets would sit with an OFTO, appointed via a competitive tender. The timing of the tender process provides scope for competitive pressure to drive reductions in financing, capital expenditure and O&M costs as compared to any TO delivery model.

3.56. Further consideration will be required as to how best to manage the interface between the ESO or TO doing the design and the successful OFTO responsible for delivering the assets.

3.57. This model has many similarities with the 'Late OFTO Build' model already allowed for within the Tender Regulations for the current regime. This model has not been selected by offshore generators for any project to date.

Option 4 – Early OFTO Competition

3.58. This option would require the incumbent TO or the ESO to carry out the detailed design for any shared infrastructure, prior to a competitive tender process to appoint an OFTO to consent, build and operate the assets. It should be noted that while the TOs have experience of detailed technical design of network assets this as a competence the ESO would need to develop.

3.59. As an example of 'early competition' there is scope for benefits from innovation in design and construction. However, the ability for the OFTO to deliver design benefits would be limited by the detailed design undertaken by the ESO or a TO. We do not yet know the extent to which the there would be an appetite among OFTO bidders for a model where the OFTO is required to seek planning consent on a detailed design undertaken by another body.

Option 5 – Very Early OFTO Competition

3.60. This option would see a competitive tender process for the appointment of an OFTO after the HND has been completed, with the appointed OFTO responsible for undertaking the DND, consenting, financing, construction, and operation of infrastructure.

3.61. This option brings maximum scope for competition including a greater role for innovation at the detailed design phase. It also reduces delivery interfaces as the OFTO develops most of the project. However, we would need to develop mitigations to the challenges set out in paragraph 3.43 (eg change control processes for costs). The arrangements for early model competition in onshore electricity transmission networks recently set out by the ESO[36] may be helpful in this regard, and we note that Ofgem intends to consult on these in late July. Similarly, BEIS is planning on consulting in the summer on legislative changes to enable competition in onshore electricity networks. Given the parallels in the concepts and competitive elements between the offshore delivery models outlined and the works on onshore competition a convergence of these models further in the future

[36] Early Competition Plan Project | National Grid ESO

appears possible. Removing the current distinctions between the onshore and offshore transmission regime could potentially even lead to just a single regime across onshore/offshore with a common model of competition further down the line and could eg be considered under the Enduring Regime workstream.

Option 6 – Developer design and build, OFTO operate

3.62. This option is analogous to the generator-build option used to date in the current OFTO regime. For shared infrastructure, as with the other options above, HND would be carried out by the ESO. After this, the offshore generator would undertake DND, consenting and construction of shared infrastructure and a competitive tender process would be carried out to transfer ownership of operational assets to an OFTO. This could require the offshore generator to oversee the development and construction of assets beyond those required for the first offshore wind farm.

3.63. In terms of implementation, this option would likely be the most straightforward as it bears many similarities to the status quo. However, as an example of a 'very late competition', there is less scope for early-stage innovation or to exert competitive pressure on construction costs beyond those which the developer builds in to its procurement processes. There may well be appetite on the part of developers to build this infrastructure given they have done this in GB since the inception of the industry. However, further work would be required to ensure the appropriate incentives exist for generators to build network infrastructure for assets beyond those required for their specific projects.

Question 11: Do you agree that the existing developer led model should be retained and applied where the HND indicates a radial solution should be used? Please explain your answer.

Further Considerations

Deliverability – Development and Construction

3.64. There are three possible parties to undertake the development and construction of offshore infrastructure – TOs, offshore generators or OFTOs. While TOs have significant experience in consenting and delivering onshore transmission they do not have the same experience as regards to offshore infrastructure. To date, no OFTO has managed the development or construction of offshore assets.

3.65. Offshore generators have the most experience of managing offshore development and construction. Even with this extensive experience, there have been examples of transmission infrastructure being delayed. Under the current regime, it is the generator who effectively underwrites this risk and they are incentivised to complete assets as quickly as possible so that there is no risk of stranded wind farm assets. In any of Options 1 to 5, depending on the design of the shared infrastructure, the generator may be reliant on another party to deliver transmission assets in a timely manner to ensure they are ready for power to be exported from the offshore wind farm as soon as they are completed.

3.66. In Option 6, while the developer would have similar control over timelines as they do today, they would also be responsible for the timely delivery of infrastructure to other projects (which may or may not be owned by the same developer) or of wider network benefit. This means that any delay might not only affect them, but might affect other developers too.

3.67. In all cases therefore, the implementation of any of these options must properly take account of the competence and incentives of the party designing and building the assets, and also take account of project timelines, ensuring that there is adequate provision for running a competition (where there is one) and providing sufficient time for construction. The regime must incentivise timely and efficient delivery of transmission assets, potentially including appropriate penalties for late delivery.

Deliverability - regulatory regime development timeline

3.68. The implementation of any of the models described above will require time to allow for changes to regulatory frameworks to be developed, consulted on and implemented, as none of the models have been used before to deliver offshore transmission. Delivering infrastructure quickly is important to facilitate Government’s target of 40GW by 2030. Therefore, the time likely to be required to implement changes to regulatory frameworks will be a factor informing our decision on a preferred delivery model within this workstream. We will decide on the delivery model we are minded to implement before the end of the year and will then run a public consultation on the detailed implementation of the chosen model.

3.69. Option 6 is the model closest to that which has been selected by developers to date. Changes are likely to be required to the regulatory framework to deliver coordinated infrastructure in line with the HND. However, these changes may be less time intensive and complex than the work required to implement some of the other models.

3.70. Option 3 is essentially a hybrid of the late OFTO build model and the late CATO model[37]. Therefore, substantial thinking has already been undertaken on this model, in terms of the underpinning policy on tender process, and market offering (ie obligations, revenue and incentives), and in terms of the legislative framework (the late OFTO build model is already set out in the OFTO Tender Regulations). However, no developer to date has elected to use the late OFTO build model, so time would be required to develop the detailed tender documentation and to determine what changes would be necessary to the current OFTO Tender Regulations. Time would also be required to create the appropriate regulatory framework for the work carried out by the ESO and TOs (noting that this also applies to options one, two and four).

3.71. Options 4 and 5 are similar to the early CATO model in that a competition would be held early, relative to other options, in a project's development. As set out earlier, substantial work has been undertaken by the ESO in developing a potential framework for onshore electricity transmission. However, the existing OFTO regulatory framework does not allow for a competition to be run this early in a project's development. Significant work would therefore be required to apply this within the offshore transmission frameworks.

3.72. Options 1 and 2 would involve amendments to the incumbent TOs' licences and funding arrangements. Whether for Option 1 or Option 2 this would involve significant work. Option 2 is likely to pose more complex problems than Option 1 in that we would need to develop a mechanism for transferring assets from a TO to an OFTO which in itself is likely to be complex. We will also need to consider further whether or not Option 1 would require amendments to primary legislation. Whether or not amendments are required will be determined by the primary use of the assets being delivered.

[37] Extending competition in electricity transmission July 2016 consultation (ofgem.gov.uk) – Chapter 2

Question 12: Please provide your views on each of the delivery options we have described in this document. In providing your views, please comment on the issues we have raised. Please also give your views on the implementation issues we have raised.

Question 13: Please describe any feasible delivery options that we have not set out in this document.

Charging and other code changes for Pathway to 2030

Charging

3.73. We anticipate, that this workstream as with the rest of the OTNR, may result in offshore transmission infrastructure that is shared and meshed to a greater degree than in offshore transmission systems to date.

3.74. Subject to the complexity of the network design outputs, we anticipate that this might require more fundamental modifications to charging arrangements than in the Early Opportunities workstream. We recognise sufficient certainty is important for developers to progress, and that confirmation of the charging and other code changes are important in providing that certainty.

3.75. The Significant Code Review process provides a tool for Ofgem to initiate wide ranging and holistic change and to implement reform to a code based issue[38]. We will need to assess the case for launching a SCR, with its own guiding principles. Part of this assessment will include the extent to which there is clarity over the likely network design requirements, or if this can be addressed in parallel with any SCR. Absent an SCR, there is a risk that code changes are made in a more piecemeal manner, which could result in inefficiencies given the potential for more fundamental reforms to enable Pathway to 2030. We would consult before deciding on whether to undertake an SCR.

[38] scr_guidance.pdf (ofgem.gov.uk)

3.76. As noted above, the Pathway to 2030 may result in offshore transmission infrastructure that is increasingly shared and meshed, more closely resembling the onshore network. In that respect, we would expect any charging arrangements to more closely align with the onshore arrangements, to the extent that they are fit for purpose. Though, as we noted in our Access SCR minded-to consultation, there is increasing evidence that we need to undertake a wider review of TNUoS charges and we will engage further with industry on the scope of further development of TNUoS charges and the mechanism for delivery.

3.77. Notwithstanding this uncertainty, the list below sets out principles to be considered when recovering the costs of coordinated infrastructure in Pathway to 2030. While this list is not exhaustive, we consider these principles will help to achieve the OTNR objective.

- The charging arrangements should be reviewed to enable the locational differences in charges for offshore users to better reflect the differences in costs that different offshore users confer on the system. For example, through the location of their onshore connection(s).
- Network users should face cost-reflective charges for network access and/or usage, ie their costs reflect the cost of the offshore infrastructure assets that are available to them to use, based on the extent they can use them (capacity) and benefits these assets confer on the system.
- The charging arrangements should ensure that charge avoidance isn't enabled or incentivised. For example, this may require assessment of whether the existing definition of a main integrated transmission system (MITS) Node is appropriate for coordinated infrastructure in Pathway to 2030[39].

Other Code changes

3.78. As with charging arrangements, we anticipate more fundamental reform of the wider industry codes and standards in this workstream than in Early Opportunities.

[39] The definition is included in CUSC – Section 11
https://www.nationalgrideso.com/document/91396/download

3.79. We expect these changes will support the implementation of the network design and delivery options, and define the detailed technical requirements for the planning, design, and operation of the network which those options will deliver.

3.80. One expected output of the HND – as set out in the network design ToRs – is the identification of recommended changes to industry technical and commercial codes, standards, and licences. For example, the current criteria set out in the NETS SQSS for offshore design are different to those for the onshore transmission network, which may limit the scope of the offshore design solutions within this workstream. In addition, consideration will need to be given to how the requirements of the Grid Code would apply to connections to, and the operation and use of, more integrated offshore network designs.

3.81. We expect that the identification of changes to codes for Pathway to 2030 and the development of SQSS for offshore network design to take place in parallel to the development of the holistic network design.

Next steps

3.82. We have noted throughout this chapter where we expect to undertake further analysis on the different options discussed above. In addition, we will undertake an impact assessment and following this consultation, analyse the responses received.

3.83. Following this consultation, further analysis and stakeholder engagement, we intend to make a decision on our preferred delivery model this year. We will then consult on how to implement our preferred delivery model.

3.84. In parallel throughout the remainder of this year the ESO will continue work on the HND. We expect this work to be concluded by the end of January 2022.

3.85. As with charging arrangements, we anticipate a more fundamental reform of the wider industry codes and standards in this workstream than in Early Opportunities. As part of our decision and further consultation on the implementation of the delivery models we will consult on our proposals to take forward any required code changes.

Summary of Pathway to 2030 questions

Question 8: We consider that a holistic design will result in a more coordinated, economic and efficient network. Do you agree? Please give reasons for your answer.

Question 9: Do you agree with the planned work for a detailed network design offshore?

Question 10: Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

Question 11: Do you agree that the existing developer led model should be retained and applied where the HND indicates a radial solution should be used? Please explain your answer.

Question 12: Please provide your views on each of the delivery options we have described in this document. In providing your views, please comment on the issues we have raised. Please also give your views on the implementation issues we have raised.

Question 13: Please describe any feasible delivery options that we have not set out in this document.

4. Multi-Purpose Interconnectors

Section summary

This section of the consultation looks specifically at classification, licencing, and ownership of multi-purpose interconnectors (MPIs) within the current legal framework in GB, as well as the potential application of the cap and floor regime, and the impact of market arrangements.

We explore options and invite views from stakeholders to inform ongoing policy development. We do not set out firm proposals. In particular we are keen to hear from developers on how the component assets of an MPI are expected to be used and their views on the feasibility and risk associated with some of the options we set out.

Introduction

Our objective for the Multi-Purpose Interconnectors (MPI) workstream

4.1. The objective of the Offshore Transmission Network Review's MPIs workstream is to explore amendments to the current regulatory and legal framework to facilitate MPIs. It will do this in two ways: Ofgem will lead work on incremental changes to the existing framework to facilitate MPIs in the near term; and the Department for Business Energy and Industrial Strategy (BEIS) will lead work exploring the need for and benefit of legislative change, with a view to potentially creating an enduring MPI regime via changes/updates to the Electricity Act 1989 ('the Act')[40].

4.2. In parallel to the work Ofgem is undertaking as part of this consultation to assess non-legislative solutions for MPIs, BEIS is exploring whether legislative change is necessary or

[40] Electricity Act 1989 (legislation.gov.uk)

beneficial. It is possible that BEIS could introduce changes considered in future BEIS-led consultations to ensure it captures MPI projects.

4.3. It is therefore important for us to be clear to stakeholders that while there are elements of this workstream that are being led by Ofgem and others that are led by BEIS, they are interrelated and informing each other under the OTNR and workstream governance. The OTNR may conclude that a non-legislative solution can be in place ahead of a legislative one to provide an interim model through which MPIs can progress; or it may conclude that *either* a legislative change or a non-legislative solution provides an enduring solution.

4.4. This consultation will provide the OTNR with a useful evidence base to support the policy options being explored by both Ofgem and BEIS. To this end, there are sections within this consultation – specifically Market Arrangements – where BEIS is directly inviting input from stakeholders. In due course, BEIS will be issuing a consultation that will provide an opportunity for input from stakeholders on the merits of legislative change, for example on the introduction of an MPI asset and activity classification.

4.5. Through Early Opportunities – a separate but related workstream of the OTNR – Ofgem seeks to remove barriers to coordination by identifying amendments to the current regulatory framework, for example Cost Assessment Guidance and charging arrangements. This is intended to facilitate new transmission concepts to increase the level of coordination in the near term. There are multiple concepts under consideration, including MPIs. Thus, barriers to MPIs that are common to all concepts – which include charging and anticipatory investment – are addressed in the Early Opportunities chapter, whereas this chapter focuses on the licencing, classification, and ownership barriers to MPIs.

Background

4.6. Electricity interconnectors ("interconnectors") are physical links which allow electricity to flow across borders and markets. Interconnectors enable the trade of energy into and out of the Great Britain (GB) market which can result in lower electricity bills and greater security of supply within GB. In addition, they can enhance the European energy market and enable the efficient integration of new renewable energy sources and, as a result, facilitate decarbonisation[41].

4.7. Interconnectors are an established asset type with a dedicated regulatory route to market through our cap and floor regime, which has been in place since 2014[42]. Interconnector developers can also select an exemption route for regulatory approval. There are currently six electricity interconnectors in operation connecting GB to neighbouring markets, with a total capacity of 6GW. There are a further three links under construction, to Norway (North Sea Link), Denmark (Viking Link), and France (ElecLink), and five more with regulatory approval at various stages of development.

4.8. A MPI is a project that serves more than one purpose of electricity transmission, namely, to combine interconnection with offshore transmission. Similar to interconnectors, MPIs create the opportunity for market-to-market integration, the benefits of which have been highlighted before by Ofgem[43]. This includes increasing the capacity for cross-border trade and thus providing benefits to the countries at both ends of the link, enhancing security of supply, increasing competition, and providing additional system services (such as cross-border balancing and reserve). Further, by combining interconnection with direct connections to offshore wind farms, MPIs also have the potential benefit of reducing disruption to coastal communities and reduce capacity costs due to reduced landing sites and associated infrastructure required. A benefits case for MPIs will be set out by BEIS in later OTNR consultations.

4.9. As our seas become more crowded, and efforts are undertaken to achieve greater coordination of offshore transmission, it is becoming increasingly important for BEIS and Ofgem to explore options to facilitate MPIs in a way that realises their potential benefits. To date, there are no such operational projects which connect to the GB market although from our engagement with industry we are aware of various projects in the development stage which would link into the GB market and could be operational by the late 2020s.

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[41] https://www.gov.uk/government/publications/impact-of-interconnectors-on-decarbonisation
[42] As an alternative to the cap and floor model, developers can seek exemptions from regulatory requirements. Under this route developers would face the full upside and downside of the investment and would usually apply for an exemption from certain regulatory requirements to better enable the business case of their investment
[43] regulation_transmission_connecting_nongb_generation2_0.pdf

4.10. Since an MPI would combine onshore, offshore and interconnection assets, it is currently unclear to industry which regulatory approach would apply to the component parts of an MPI. BEIS and Ofgem are committed to removing any regulatory barriers for MPI projects in development or for those that might come forward in the future, where to do so would be for the benefit of consumers.

4.11. The Electricity System Operator's (ESO) Offshore Coordination Phase 1 report published in December 2020[44] reports that adopting greater coordination for all offshore projects 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; or savings of £3 billion against the status quo for adopting greater coordination from 2030. The report also highlights the significant environmental and social benefits associated with an integrated approach, due to the reduction (up to 50%) in the number of new electricity infrastructure assets, including cables and onshore landing points. MPIs play a role in delivering these benefits.

4.12. In 2012 Ofgem set up the Integrated Transmission Planning and Regulation (ITPR) project to review the existing arrangements for planning and delivering the onshore, offshore, and cross-border electricity transmission networks in GB. Our aim was to ensure that transmission is developed in an efficient, coordinated, and economic manner, with the right investments made to protect existing and future consumers. In this review we considered how regulatory barriers for multi-purpose projects (MPPs) could be addressed. An MPP was defined through the ITPR as a project that features some combination of onshore transmission, offshore transmission or interconnection[45]. For clarity, an MPI would be an MPP; however there will also be MPPs that are not MPIs.

4.13. In our ITPR conclusions[46], we signalled the importance of clarifying the regulatory approach to MPPs (which includes MPIs) to encourage and enable investment in flexible, coordinated network solutions. We also discussed the merits of increasing flexibility in how we regulate different asset types to bring about benefits for consumers.

4.14. A key conclusion was that we should maintain continuity in the regulatory treatment of an existing transmission asset if it evolves into an MPP. In such cases, we stated that we

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[44] Offshore Coordination Project | National Grid ESO
[45] itpr_final_conclusions_decision_statement_publication_final.pdf
[46] Integrated Transmission Planning and Regulation (ITPR) project: final conclusions | Ofgem

would look to ensure the GB regulatory arrangements do not require a change in ownership, and that owners of an existing asset are 'at least as well off' from forming an MPP, provided the MPP is economic and efficient. For any project which would be an MPP from the outset, we said we would work with the relevant parties to determine the most appropriate treatment. We highlighted that treatment of specific MPPs, such as MPIs, would also need to consider EU requirements, for example requirements relating to unbundling and third-party access.

4.15. It is our intention that in the treatment of MPIs in this consultation we build upon the conclusions of the ITPR rather than replace or duplicate them. As such, we have sought to reflect those conclusions in our thinking both through the OTNR and our ongoing Interconnector Policy Review[47], which is described in a later section. We are working carefully across these reviews and with BEIS to ensure that our engagement with stakeholders and consideration of policy issues is coherent and complementary to each programme of work.

Our work so far

4.16. The OTNR was launched[48] in July 2020. In August 2020, BEIS and Ofgem issued a joint Open Letter[49] in which we called for stakeholder views to support the OTNR. In particular, we sought views from stakeholders who were either already pursuing some level of coordination or had identified an opportunity to do so whether on a local, national or international level (such as considering anticipatory investment in one project to enable a future project, or combining offshore wind and interconnector assets). Stakeholder views are summarised in the BEIS and Ofgem Open Letter response[50].

4.17. Since publishing the Open Letter response, Ofgem and BEIS have engaged extensively with MPI developers and wider stakeholders in GB and in neighbouring countries to determine the key barriers applicable to the GB side of an MPI project. These engagements have informed the considerations detailed in this consultation by allowing us to explore key project barriers in more detail and to take a wide range of views into account. Barriers and

[47] Open letter: Notification to interested stakeholders of our interconnector policy review | Ofgem
[48] Offshore transmission network review - GOV.UK (www.gov.uk)
[49] Increasing the level of coordination in offshore electricity infrastructure: BEIS and Ofgem open letter to developers of offshore wind generation, electricity transmission licensees, and other interested parties | Ofgem
[50] BEIS and Ofgem joint response to the Open Letter engagement

opportunities raised by industry have also been considered with key OTNR project partners such as the ESO.

Approach to consultation

4.18. This section of the consultation looks specifically at the challenge of classification, licencing, and ownership of MPIs within the current legal framework, as well as the potential application of the interconnector cap and floor regime, and the impact of market arrangements.

4.19. At this stage, we explore options and invite views from stakeholders to inform ongoing policy development. We do not set out firm proposals. We are keen to hear from developers around how the component assets of an MPI are expected to be used and their views on the feasibility and risk associated with some of the options we have set out.

4.20. BEIS is exploring in parallel whether legislative change could better facilitate MPIs. To support this thinking, we have incorporated questions from BEIS within this consultation on market arrangements. This is an effort to move quickly and be agile in our approach across the different workstreams of the OTNR. BEIS expects to publish a consultation on the Enduring Regime, including for MPIs, later in the year.

4.21. In addition, alongside our work on MPIs through the OTNR, we are also undertaking an Interconnector Policy Review (ICPR), which has recently published its working papers[51]. We describe the linkages across the two reviews later in this chapter.

4.22. The principles and outcomes that Ofgem seeks to achieve through changes to the current framework are intended to remove barriers which are common to all early opportunity concepts – eg in respect of anticipatory investment and charging. These are described in the

[51] Interconnector policy review: Working paper for Workstream 1 – review of the cap and floor regime | Ofgem
Interconnector policy review: Working paper for Workstream 2 – socio-economic modelling | Ofgem
Interconnector policy review: Working paper for Workstream 3 - wider impacts of interconnection | Ofgem
Interconnector policy review: Working paper for Workstream 4 - multiple purpose interconnectors | Ofgem

Early Opportunities chapter, and we are inviting views from stakeholders on those considerations.

Multi-Purpose Interconnectors Models

4.23. We are currently engaging with developers that are proposing two main concepts for MPI development through the OTNR. These are described below and illustrated in Figure 13:

- **the interconnector-led (IC-led) model** where the point-to-point interconnector cable also includes direct connection(s) with GB offshore wind farm(s) which use the interconnector as their connection to market.

- **the OFTO-led model** where a radial connection to shore from a GB offshore wind farm is combined with a further direct connection between the GB offshore wind farm and the electricity network or offshore wind farm of a neighbouring country or territory. The further direct connection forms an interconnector and therefore provides for cross-border electricity flows in addition to the offshore wind farm connection.

4.24. For the enduring regime BEIS – together with Ofgem – will need to consider the potential for further development models to be introduced, including offshore hubs, which would connect larger wind capacities to a number of countries and also the deployment of further technologies (including storage and power-to-cross-vector conversion).

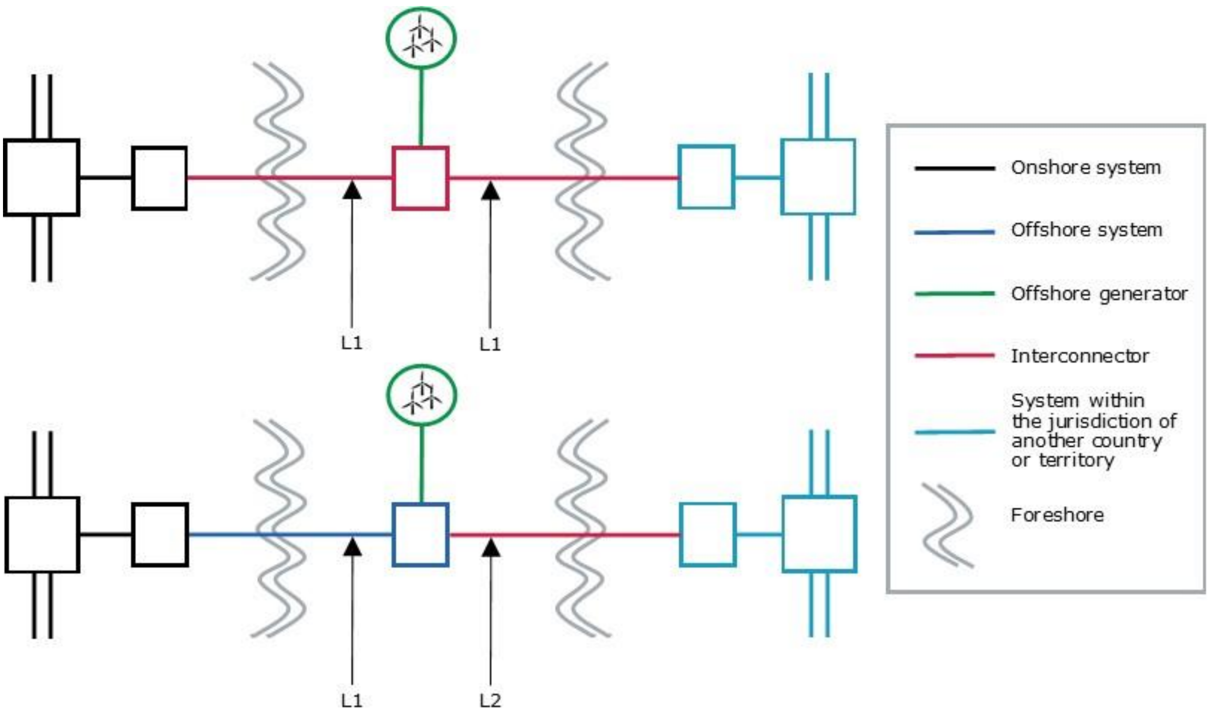

Figure 13 Interconnector (IC)-led MPI model (top) and OFTO-led MPI model (bottom)

Question 14: Do you think we are focusing on the right models at this stage, or are there other models we should be considering? Is it also necessary to consider the evolution of such MPIs from pre-existing assets? Ultimately, should Ofgem accommodate multiple MPI models (e.g. IC-led and OFTO-led) or just one? What factors influence your answer?

Ownership, licencing, and classification of MPIs

Current application of legal framework

4.25. The question of asset classification is important for a number of reasons. Assets, such as interconnectors or offshore transmission (commonly referred to as 'OFTOs'), are classified based on their primary function. We then regulate assets based on this function, primarily by way of a licence. Different licence types have different requirements depending on the asset being regulated.

4.26. Section 4 of the Electricity Act 1989 (the 'Act') prescribes that certain activities cannot be undertaken unless authorised by licence, which under the current framework would be granted by Ofgem following an application. Thus, a person who undertakes any of the following activities requires a licence:

- Generation of electricity for the purpose of giving a supply to any premises or enabling a supply to be so given;
- Participation in the transmission of electricity for that purpose;
- Distribution of electricity for that purpose;
- Supply of electricity to any premises,
- Participation in the operation of an electricity interconnector;
- Provision of a smart meter communication service.

4.27. The type of asset and prohibited activity undertaken by that asset determines what type of licence(s) will be needed, and by extension the regulatory framework to which the asset would normally be subject.

4.28. The Act currently has no provision for a specific MPI activity, and as such, to be able to licence an MPI within the current legal framework we need to consider how to classify the individual components of an MPI. This would enable us to grant a licence and regulate the activity appropriately.

4.29. The Act contains several other important requirements to which we must adhere in developing options. We have focused on the most relevant provisions of the Act, which are set out in Table 5, to consider what flexibilities and opportunities – if any – are available to us in the absence of legislative change.

Table 5 Applicable areas of the Act

Act reference	Summary of rule	Relevant content of Act
s4 EA 89	An interconnector licence is required for an asset that meets the definition of an interconnector	'so much of an electric line or other electrical plant as […] subsists wholly or primarily_for the purposes of the conveyance of electricity […] between Great Britain and a place within the jurisdiction of another country or territory'
s6C EA 89	An OFTO licence is required for an asset	OFTO licence is required to authorise any activity that 'forms part of a transmission system to be used for

	that undertakes offshore transmission	purposes connected with offshore transmission'… with offshore transmission defined as 'the transmission within an area of offshore waters of electricity generated by a generating station in such an area.' The definition of 'transmission system' in this context is such that an OFTO licence is required for transmission lines constructed 'wholly or mainly_for the purpose of conveying, to any other place, electricity generated [offshore]'
s6(2A) EA 89	It is not possible for the owner of an interconnector to hold multiple licences per asset	'The same person may not be the holder of an interconnector licence and the holder of a licence falling within any of paragraphs (a) to (d) of subsection 1' ie … an electricity generation licence, transmission licence, distribution licence, or supply licence.
s10A-O EA 89	It is not possible to have common ownership or control of transmission, generation, and interconnection assets	Under ownership unbundling, the same person or persons are generally not entitled to control a producer or supplier and, at the same time, control or exercise any right over a transmission system operator or transmission system
s5 EA 89	The Secretary of State has the power to exempt licence requirement	The Secretary of State may by order grant exemption from paragraph (a), (b), (bb), (c), (d) or (e) of section 4(1)

Ownership structures of MPIs

4.30. Under Section 6(2A) of the Act it is not possible to hold an interconnector licence and an OFTO or generation licence, so in the absence of any legislative change it may be necessary to have separate owners operating the interconnector, generation and OFTO assets of an MPI project. While there is no similar statutory blocker to an OFTO licence holder also holding a generation licence, the ownership unbundling requirements (referenced in Table 5) are drafted to prevent common ownership of connected transmission and generation assets, although it is possible for the Authority to treat any of the five unbundling tests as passed in certain circumstances.

4.31. The collective effect of these provisions is that, under the current legal framework, an MPI would need to operate such that the different components of the MPI are owned and operated by different legal entities, each with its own licence – ie separate ownership of the OFTO, interconnector and generation assets. Any significant development away from this model, for example with a single owner/operator of the transmission and interconnection assets, would likely require changes to primary legislation. We would like to hear your views on this.

Question 15: Do you agree with this position with regard to ownership structures of MPIs under the current framework?

Classification and licencing of MPIs

4.32. Given the multi usage of an MPI we have a new challenge of having to determine the primary use of the individual assets within an MPI in order to grant the appropriate licence. A key challenge is how we define and licence the activity undertaken by the asset that conveys electricity from the offshore substation to the GB shore (see Figure 14).

4.33. In the two models presented to us, the electrical nature and physical configurations of the set-ups are broadly comparable. However, there might be a number of reasons why developers may prefer one model over the other, including construction sequence, familiarity with regulatory regime (cap and floor or OFTO Tender Revenue Stream), or indeed the primary use of the asset.

4.34. Given the importance of granting a licence that appropriately reflects the activity being undertaken, we would like to understand how developers envisage the usage of the line to shore to vary across the two MPI models proposed and whether factors such as construction sequence would influence which model is more suitable (from a developer’s perspective) for a particular MPI project.

Question 16: What are the commercial, operational and regulatory factors that would drive a developers preference for either the OFTO-led or IC-led MPI model? and do you envisage a different usage of the component assets of an MPI depending on the MPI model?

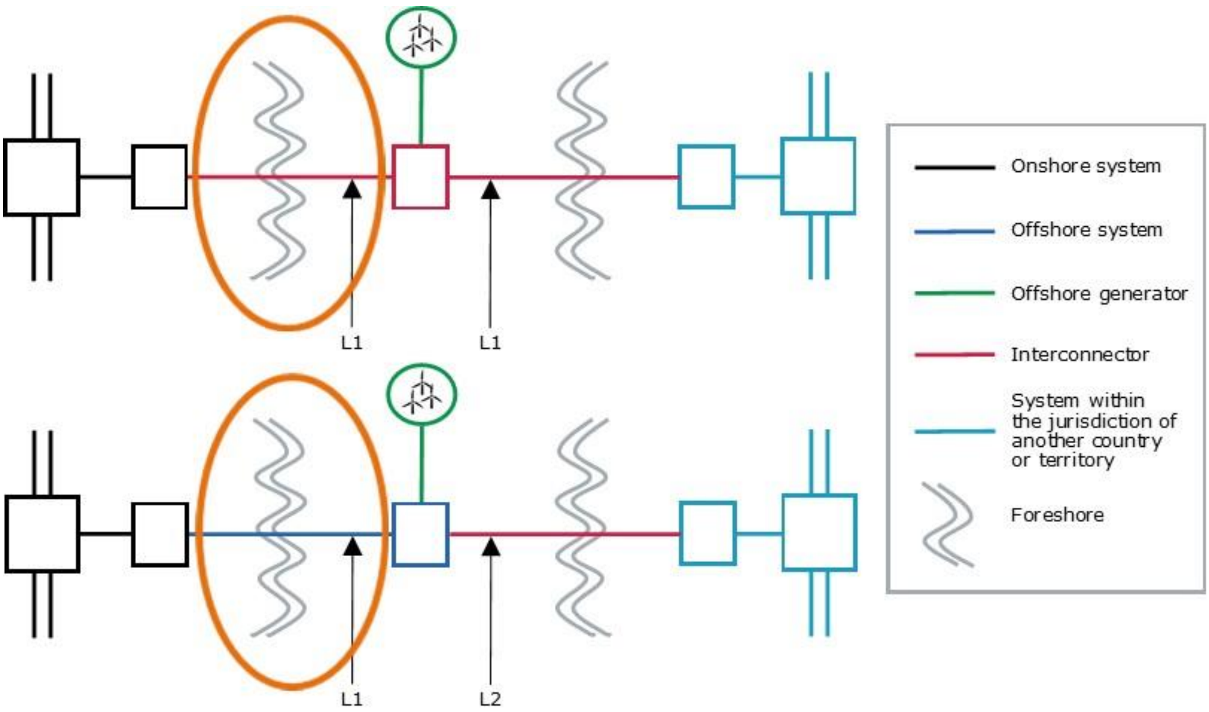

Figure 14 Interconnector (IC)-led MPI model (top) and OFTO-led MPI model (bottom)

Classification and licencing assets – OFTO-led model

4.35. In Figure 144 which shows the OFTO-led model, the proposed interconnector (L2) connects into the GB market at the offshore substation. While this configuration does not yet exist in GB, our analysis to date would indicate that neither the applicable regulations nor the Act prevent an interconnector connecting to the GB market through an offshore substation (as long as that substation is in the GB jurisdiction). The only activity the interconnector in this configuration appears to undertake is that of interconnection. Even if it is used to transport electricity generated from the GB wind farm to another jurisdiction, the electricity would be leaving GB jurisdiction for conveyance to another jurisdiction and thus fall under the definition in the Act of interconnection as described in Table 5.

4.36. In this same model, the line to shore (L1) is proposed as an OFTO. In this case, our understanding is that the asset would be used for a combination of transmitting electricity generated offshore (from the GB wind farm) and conveying electricity between the offshore substation and the GB shore.

4.37. We would expect that the proposal from industry to classify L1 as an OFTO would be based on how the model would work in practice and the sequence of construction ie that the primary activity would be offshore transmission and that L1 (the OFTO) would be constructed before L2 (the interconnector).

4.38. However, for the purposes of understanding asset activity overall we need to explore both the primary and the 'secondary' activities. From our engagement so far, this is unclear to us. Therefore, we are keen to understand more about how L1 would be used in practice and how developers would categorise any secondary activity eg transmission or interconnection. We acknowledge that the definitions within the Act are linked to the purpose of the construction of the asset or system that is undertaking that activity, which makes it difficult to define any sort of secondary activity based on the Act. As such, we are looking to understand secondary activity from a practical – rather than strictly legislative – perspective.

Classification and licencing assets – IC-led model

4.39. In the case of the IC-led model, the proposed classification of both the line to shore and the line connecting the GB market to that of a neighbouring country is an interconnector. A key difference in this model compared to the OFTO-led model is that these two lines are proposed as a single asset (rather than two assets). As such, the line to shore (L1) would be part of the same asset conveying electricity to the neighbouring country (also L1).

4.40. In order for Ofgem to grant an interconnector licence to L1 (as is proposed in this model), we would need to determine that the asset in its entirety is consistent with the definition within the Act set out in Table 5**Error! Reference source not found.**, namely that the asset exists *primarily* for the purpose of conveying electricity between GB and another country or territory. Below we explore whether this is the case.

4.41. As with the OFTO-led model, we are comfortable that when the asset is being used to convey electricity from GB to the market of a neighbouring country, or where it is being used to convey electricity to another jurisdiction that is dispatched directly from the GB wind farm, this activity would fall under the Act's definition of interconnection. As such, if this is the primary reason for its construction, we could be comfortable that the correct licence to grant is an interconnector licence.

4.42. However, we need to understand the activity being undertaken from the proportion of L1 that conveys electricity from the offshore substation to GB shore. Our understanding is that the offshore substation would be an interconnector asset. This asset will be transporting electricity produced by the offshore generator to the GB shore and into the national electricity transmission system.

4.43. Early engagement with developers has suggested that the commercial viability of MPI projects is underpinned by the requirement to provide priority access to the offshore wind element of the project. We therefore envisage a scenario that the primary activity undertaken by this part of the IC asset might meet the criteria of offshore transmission[52] as opposed to interconnection. Ofgem needs to understand the activity overall and would therefore like to understand how this part of the asset in the IC-led model will be used in practice and whether this differs from the OFTO-led model.

Question 17: How would the line to shore (L1) be used in practice and what would you consider to be the primary and secondary activities from a practical perspective? Please provide views for both the IC-led and OFTO-led models, highlighting any differences between L1 usages across the two models.

Question 18: Are there any barriers within the current frameworks, such as definitions within the CUSC, SQSS or other industry codes, that might prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities?

Considering a framework to assess and monitor MPI licence applications

4.44. In the absence of legislative change (which could, for example, introduce an MPI activity within the Act), we are interested in understanding what sort of scenarios and what level of flexibility Ofgem might need to consider in terms of how we licence and regulate assets that form part of an MPI. For example, project construction sequence and changes in asset usage over time might be factors that affect what licence should be granted. If flexibility is required in how Ofgem views those factors when considering how to licence an asset, then we need to understand this from stakeholders. This is important in ensuring we support commercial viability, while at the same time providing Ofgem with enough certainty to be able to regulate effectively.

4.45. If Ofgem were to adopt a framework that requires applicants to demonstrate – with evidence – the primary usage of a particular asset in order to receive the requested licence,

[52] In summary, Ofgem's interpretation of the Act is that an OFTO licence is required for assets where the asset is constructed wholly or mainly for the purposes of offshore transmission.

this would be a new mechanism for the industry. Such a framework might also include a mechanism to allow Ofgem to monitor the ongoing usage of assets to ensure that the licence issued remains appropriate over time, and to take action if the usage evolved beyond the purposes envisaged when the licence was granted.

4.46. We are not aware of any existing formula for calculating the primary function of either an OFTO or interconnector; however, there are regimes from which we could borrow. The cap and floor regime requires applicants to achieve a minimum availability level of 80%. Developers must submit regular performance reports to Ofgem. If a developer were to fall below the required levels, their cap and floor revenue would be removed for the period of non-compliance. Similarly, there is an availability mechanism in the OFTO framework from which we could borrow. We are interested to hear from stakeholders around what could work for MPIs and any challenges with the sorts of regimes mentioned that we should be considering.

4.47. Another option could be to rely on documentation such as long-term capacity contracts for the generators, or the MPI design, where relevant capacities could demonstrate primary activity of assets.

Question 19: What are your views on the feasibility of adopting a regime that requires developers to submit evidence to support their licence application (for assets that form part of an MPI) and commit to regular performance reports? Would this be practicable, proportionate, and effective? Are there other options that work well for industry that we could explore further?

4.48. In order to ensure that the relevant licence obligations were in place for each project, we would expect that we may need to make modifications to the licences granted to projects to ensure that any secondary activity it undertakes is effectively regulated[53]. This could be

[53] As allowed for under Section 8A Standard Conditions of Licences of ‘the Act’: Subject to …. provisions of this section, the Authority may, in granting a licence of any type, modify any of the standard conditions for licences of that type in its application to the licence to such extent as it considers requisite to meet the circumstances of the particular case.

achieved for example by including the additional obligations for the secondary activity by way of special licence conditions into the licence remaining.

Question 20: What are your views on the practicality of transposing obligations from one licence into another, which obligations would be the most important to incorporate into a remaining licence?

Considering licence exemption options for MPIs

4.49. We are interested to understand from developers whether there might be benefit in making use of the provision within Section 5 of the Act for the Secretary of State (SoS) to grant exemptions from Section 4 that prohibits certain activities being undertaken without a licence. For example, there could be merit in having an exemption for a limited period for one asset of an MPI while the other is under construction.

Question 21: Do you think the exemption provision with the Act offers any solutions to licencing MPIs within the current framework, even if only a temporary solution until a potential enduring solution is implemented?

Suitability of the cap and floor regime for MPIs

Background

4.50. Ofgem created the cap and floor regime in 2014 to encourage investment in electricity interconnectors. It strikes a balance between commercial incentives and appropriate risk mitigation for project developers. The regime was designed to deliver a new generation of interconnectors that would benefit GB energy consumers.

4.51. Electricity interconnectors developed under the cap and floor regime will earn revenue from the allocation of capacity to users who want to flow electricity between GB and our neighbours. Interconnectors may also earn additional revenue streams, such as from participating in the GB capacity market or providing services to system operators. The floor provides a minimum return that an electricity interconnector can earn[54]. This means that, if an interconnector does not receive enough revenue from its operations, its revenue will be ‘topped up’ to the floor level. The funds will be transferred from the ESO, which will in turn recover the sum from transmission charges applied to all users of the national electricity transmission system.

4.52. The cap and floor levels are determined by the following building blocks of capital costs, operations and maintenance costs, decommissioning costs, tax and allowed return. The cap and floor levels are then profiled so that they are flat over time in real terms. The cap and floor regime duration is 25 years, and actual revenues earned are assessed against the cap and floor levels every five years. Interconnectors may also request a within-period adjustment during a five-year period, for financeability reasons or in anticipation of a large end of period adjustment. The regime also includes some risk-share with consumers for force majeure events. Developers granted a cap and floor regime will need to comply with relevant GB legislation and industry codes (such as use of revenues and unbundling requirements). Developers may also request regime variations in order to reflect project-specific circumstances. This could include, for example, variations to better enable investment via project finance.

Interconnector Policy Review

4.53. In August 2020, Ofgem launched a review of its regulatory policy and approach to new electricity interconnectors[55]. The first objective of the Interconnector Policy Review (ICPR) is to establish whether there is a need for further GB interconnection capacity beyond those projects currently with regulatory approval. If so, the second objective of this review is to consider Ofgem’s approach to the regulation of future GB interconnection.

4.54. The review has four workstreams, with a specific workstream on MPIs which explores whether the cap and floor could be a suitable regime to support the development of

[54] To qualify for a floor payment in any given year, interconnectors must achieve a minimum of 80% availability.

[55] Open letter: Notification to interested stakeholders of our interconnector policy review (ofgem.gov.uk)

interconnectors that form part of an MPI and whether the conclusions of Ofgem's Integrated Transmission Planning and Regulation (ITPR) project[56] remain fit for purpose.

4.55. Since the open letter, Ofgem has undertaken a call for evidence with stakeholders, and published its follow up working papers[57] with conclusions and initial proposals for consultation. These are summarised below (details can be found in the references provided) and we encourage stakeholders to respond fully to both the ICPR consultations and this OTNR consultation.

ICPR Workstream 4 conclusions

4.56. The ICPR conclusions are as follows:

- Ofgem recognises the benefits MPIs can deliver. MPIs can potentially reduce the total investment and number of landing points required for interconnectors and offshore renewables and can help to facilitate the development of energy systems in a more coordinated way.

- The specific conclusions of the ITPR project with respect to our regulatory approach to MPPs, including MPIs, are not sufficient to provide the necessary regulatory certainty and clarity for the development of these projects.

- The cap and floor regime could be adapted to support the development of the interconnector part of an MPI, or potentially the project as a whole. However, further analysis is required to fully understand potential barriers to its applicability and how it interacts with other frameworks.

[56] Integrated Transmission Planning and Regulation (ITPR) project: final conclusions | Ofgem
[57] Interconnector policy review: Working paper for Workstream 1 – review of the cap and floor regime | Ofgem
Interconnector policy review: Working paper for Workstream 2 – socio-economic modelling | Ofgem
Interconnector policy review: Working paper for Workstream 3 - wider impacts of interconnection | Ofgem
Interconnector policy review: Working paper for Workstream 4 - multiple purpose interconnectors | Ofgem

- A shift towards a more system-wide and coordinated approach to identify new MPI projects may be preferable in the future. This would involve a more prominent role for the ESO to help identifying the location, capacity, and timing of new projects.

- Overall, unbundling requirements, the interaction of multiple licences and of multiple revenue streams related to operating an MPI are not considered as insurmountable barriers to the development of these projects. Charging and market arrangements are recognised as more complex and fundamental topics that will determine the successful delivery of MPI projects.

ICPR initial proposals for consultation

4.57. The initial proposals as set out in ICPR are as follows:

- Explore ways to provide regulatory certainty to developers of MPI projects. This could potentially be delivered through the cap and floor regime.

- Further consider applicability of the cap and floor regime to support the interconnector part of the early MPI projects considered under the OTNR, or potentially the project as a whole. In principle, the regime (or aspects of it) may also be suitable for future MPI projects too. We should also consider the interface with other regimes, and the interactions between a cap and floor regime for MPIs and the existing and/or potential future regime for point-to-point interconnectors.

- Explore wider energy policy issues to remove key barriers to the development of MPIs, noting that the OTNR will address some of these in more detail in due course.

Interactions between the Interconnector Policy Review and the OTNR

4.58. We expect Ofgem to publish its decision and policy recommendations for the Interconnector Policy Review (ICPR) in Autumn 2021, which aligns with when Ofgem expects to publish its next policy consultation on the OTNR.

4.59. The policy development and recommendations for each programme of work will complement each other and drive Ofgem’s direction of travel in developing a regulatory framework for MPIs. For example, the licencing route for the component assets of an MPI and how those assets are used – which is being looked at by the OTNR – will likely impact the cost and revenue streams that comprise any regulated revenue regime for MPIs such as the cap and floor, which is being considered by the ICPR.

4.60. We will continue to work together on both reviews to align thinking, share stakeholder input, and ensure coherent proposals and engagement with stakeholders.

Market arrangements

Background

4.61. Market arrangements are an important consideration in determining the primary use of the component assets of an MPI, and thus the appropriate licence route for those assets. There are a number of existing and evolving market rules, which are likely to impact how generation and interconnector assets are utilised in an MPI. In addition, the cross-border nature of MPI projects means we need to understand the consequence of rules in the European Union (EU) which will be applicable in EU Member States and therefore apply, in part, to projects connecting to the UK, as well as those in countries which MPI projects may connect to which are not part of the EU. We are therefore interested in views from stakeholders as to how these might impact on model choice and project feasibility. BEIS is also keen to seek views on wider considerations arising from MPI market arrangements.

4.62. The UK left the European Union on 31 January 2020, followed by the implementation period where certain EU rules continued to apply. Cross-border electricity trading is no longer governed by EU law and the UK has domesticated and amended direct EU legislation via the European Union (Withdrawal) Act 2018. This includes legislation relevant to electricity market design and cross-border trading.

4.63. On the 24 December 2020, the United Kingdom (UK) and the EU agreed the Trade and Cooperation Agreement (the TCA)[58], which took effect provisionally from 1 January 2021 and then entered into force on 1 May 2021. The TCA governs the new relationship between the UK and the EU and contains provisions regarding cooperation on both offshore renewable energy and efficient electricity trade, making it a key mechanism in the development of

[58] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/982648/TS_8.2021_UK_EU_EAEC_Trade_and_Cooperation_Agreement.pdf

market arrangements for MPIs. We note that Article 321 on "Cooperation in the development of offshore renewable energy" specifically addresses MPIs or "hybrid or joint projects".

4.64. The market arrangements that would currently apply to an MPI are derived from the applicable regulatory regime for cross-border electricity trading in the UK and, for those projects connecting to EU Member States, the EU. The regulations that govern the current trading regime were not designed with MPIs in mind, meaning arrangements do not support the specificities of trade over hybrid models like MPIs. The EU rules are subject to review in the EU and, due to the cross-border nature of MPIs, will have a bearing on MPIs connecting to GB.

4.65. As set out above, the OTNR in the UK will explore changes to the current regulatory and legal framework to facilitate MPIs. In the EU, the European Commission published its Offshore Renewable Energy Strategy[59] in November 2020, which seeks to assess options that better harness the potential of offshore renewable energy for a climate neutral future in the European Union. Having left the EU, the future of the GB market arrangements and how we ensure ongoing compatibility for cross-border projects with EU and other non-EU countries will be important in facilitating MPIs. It will therefore be important for GB to monitor the evolving regulation of MPI assets under EU law and consider any potential divergences on key principles, for instance on asset definitions and revenue regulation.

Priority dispatch and curtailment

4.66. In Great Britain, under Article 12 of the retained Electricity Regulation 2019/943 [60] which formed part of the EU's "Clean Energy Package", new renewable generators cannot benefit from priority dispatch (subject to a *de minimis* exemption). Article 13 of the domestic retained Regulation also requires renewable generators to be curtailed only as a last resort. This would indicate that the wind generation aspect of an MPI would not benefit from priority market access but also could not be extensively or regularly curtailed. These provisions are the same in both UK and EU Law.

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[59] November 2020, [offshore_renewable_energy_strategy.pdf (europa.eu)]
[60] Regulation (EU) 2019/943 on the internal market for electricity provides a framework for the further integration of renewable energy into the electricity market, sets out new rules on

4.67. As described by the European Commission in their 2020 Working Paper that accompanied the Offshore Renewable Energy Strategy[61] , for hybrid projects such as MPIs, the issue of priority dispatch is not only about access to a market. It is inherently linked to issues of third-party access and the flows from cross-border trade.

4.68. We are interested in how these requirements will affect model choice for MPIs connecting between the UK and EU Member States, as well as any wider impacts.

Third-Party Access Requirements

4.69. Linked to considerations of priority dispatch are the requirements of third-party access to interconnectors. Third-party access concerns the transparent, objective and non-discriminatory application of approved access rules and charging methodologies. How access is given to offshore wind and cross-zonal trade in different models of MPI may thus have implications for satisfying third-party access requirements, and the potential need for an exemption from these requirements if they cannot be met.

4.70. The EU's Electricity Regulation allows for MPIs to be eligible for exemptions from requirements including those regarding third-party access in the same way as new direct current interconnectors (through Article 63), and that "the regulatory framework should duly consider the specific situation of those assets to overcome barriers".

4.71. Through the domestic retained Electricity Regulation, an MPI exemption route, from requirements including those relating to third-party access, remains in UK law. Article 63 has been amended in domestic retained EU law to provide exemption from the standard conditions of an interconnector licence granted under section 6(1)(e) of the Electricity Act 1989 relating to (a) the provision of third-party access to an interconnector; (b) tariffs or charging methodologies for such access; (c) use of revenues[62].

4.72. Further, the TCA also provides an opportunity for third-party access exemption. In Article 308: "Public policy objectives for third-party access and ownership unbundling", to

[61] Guidance on electricity market arrangements: A future-proof market design for offshore renewable hybrid projects.
staff_working_document_on_the_offshore_renewable_energy_strategy.pdf (europa.eu)
[62] The Electricity and Gas (Internal Markets and Network Codes) (Amendment etc.) (EU Exit) Regulations 2020 https://www.legislation.gov.uk/ukdsi/2020/9780348209495/contents

fulfil a legitimate public policy objective and based on objective criteria, the UK or the EU may decide not to apply the third-party access requirements and unbundling requirements described in Article 306 and Article 307 respectively.

4.73. We are interested in how third-party access requirements, and the availabilities of exemption from these in the UK and EU, will affect model choice for MPIs connecting between the UK and EU Member States, as well as any wider impacts of this issue.

Margin Available for Cross-Zonal Trade

4.74. A further consideration affecting MPI models is the Margin Available for Cross-Zonal Trade and maximisation of capacity requirements concerning the level of capacity made available on interconnectors. For projects linked to EU Member States, Article 16(8) of the EU's Electricity Regulation states that the volume of interconnection capacity made available to market participants shall not be limited, with a minimum level of 70% of capacity available for cross-zonal trade demonstrating this provision to be met. Article 16(9) provides for short derogations from this requirement (up to a maximum of two years) for operational security.

4.75. Article 64 additionally provides for derogation from various articles of the Regulation, including Article 16, for a time-limited period for situations where "the Member State can demonstrate that there are substantial problems for the operation of small isolated systems and small connected systems". Such a derogation applies within the EU to the Kriegers-Flak Combined Grid Solution (CGS) between Denmark and Germany, as detailed in Appendix 4.

4.76. Following the end of the transition period, Article 16(8) has now been removed from domestic retained EU law, so it is no longer part of domestic law in the UK. This means that MPI developers will need to consider how the 70% threshold is applied in the EU (and whether MPIs may require an EU derogation if connecting to an EU Member State). In the UK the Article 16(8) threshold is no longer applicable, and therefore no equivalent UK derogation is required.

4.77. While Article 16(8) has been removed from domestic retained EU law, as described above, a similar but less prescriptive requirement now exists as part of the TCA. In Article 311 of the TCA: "Efficient use of electricity interconnectors", it is required that the "maximum level of capacity of electricity interconnectors is made available, respecting the: (i) need to ensure secure system operation; and (ii) most efficient use of systems". These requirements apply to the UK via the TCA, rather than the minimum capacity requirements described in Article 16(8) of Regulation (EU) 2019/943.

4.78. We are interested in how requirements concerning the margin available for cross-zonal trade and maximisation of capacity, in regulations applying to potential connecting countries and to the UK through the TCA, will affect model choice for MPIs, as well as any wider impacts of these issues.

Cross-border market arrangements

Development of new procedures for allocation of cross-border capacity

4.79. The development of cross-border trading arrangements over interconnectors will have implications for MPIs. Following the UK's exit from the EU, GB is no longer part of the Internal Energy Market, and as a result no longer has access to single day-ahead coupling and single intraday market coupling arrangements with the EU. Therefore, at present, the trading arrangements on GB's interconnectors to Continental Europe are explicit, meaning transmission capacity on the interconnector is auctioned to the market separately from electrical energy. For GB's interconnectors to the Irish electricity market, capacity is allocated via implicit[63] intraday auctions.

4.80. Given a desire to maximise the benefits of trade, the TCA requires UK and EU Transmission System Operators (TSOs) to develop new "robust and efficient" procedures for the allocation of cross-border capacity on electricity interconnectors at all timeframes, and as a matter of priority to develop technical procedures for the day-ahead timeframe, based on the implicit concept of multi-region loose volume coupling (MRLVC), with a timeline for entry into operation by April 2022.

4.81. UK and EU TSOs have delivered the first major milestone set out in Annex 29 of the TCA, which is to prepare and deliver a cost benefit analysis and outline technical procedures of MRLVC[64]. The report and supporting analysis provided by the TSOs recognises that the development of MPIs will require trading arrangements which support efficient energy pricing and capacity utilisation. We welcome that the report starts to explore some of the challenges associated with the proposed development of MPIs, including in relation to the market models

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63 Implicit trading is where the capacity on the interconnector and the energy product are bought together.

[64] Cost Benefit Analysis of Multi-Region Loose Volume Coupling (MRLVC) arrangements to apply between the UK and the bidding zones directly connected to the UK - European Network of Transmission System Operators for Electricity - Citizen Space (entsoe.eu)

(eg home bidding zone model vs. offshore bidding zone model), and how this interacts with the different MRLVC options and the counterfactuals.

4.82. We note the report states it would be very difficult for explicit auctions to support the efficient flows needed to make best use of hybrid infrastructure utilising offshore bidding zones, due to the challenges for market participants of making forecasts of price spreads involving these small bidding zones, where optimal cross-zonal flows are likely to be very sensitive to flows on adjacent borders. It is also recognised that the design and overall performance of MRLVC will be critical to the development of MPIs. The report highlights as an area of focus investigating how the current design may need to evolve in order to support MPIs, such as that there might be a need to have access to more data (for example, from non-bordering bidding zones to GB) than is currently envisaged under the TCA.

4.83. The next stages of the MRLVC project will be for TSOs to develop the technical procedures further, to be submitted to regulators for opinion, and to the Specialised Committee on Energy[65] for decision in November 2021. We are interested to understand how the trading arrangements being developed under the TCA, described above, might influence MPI models and how the component assets are used, as well as any wider considerations.

Possibilities for market design of MPIs

4.84. In parallel to the development of new procedures for the allocation of cross-border capacity, the EU commission is considering – and inviting policy discussion on – the benefits and challenges associated with different market design options for MPIs, such as bidding zones.

4.85. Two primary options can be considered for the market arrangements of offshore wind farms that are part of MPIs – the "home markets" model, whereby the wind farm forms a part of its "home" bidding zone (eg the GB market), or an "offshore bidding zone" approach, whereby a separate bidding zone exists which contains one or more offshore wind farms. The "home markets" model, as pursued by the Kriegers-Flak CGS, may present challenges in

[65] The TCA establishes a Specialised Committee on Energy (SCE) which addresses matters relating to energy under the TCA, other than those aspects relating to "energy goods and raw materials", cooperation on standards and environmental subsidies.

terms of satisfying requirements detailed in the previous section regarding priority dispatch, third-party access, and capacity availability.

4.86. Though the EU Offshore Renewable Energy Strategy report[66] highlighted benefits of an offshore bidding zone approach in terms of compatibility with current EU electricity market rules, the Strategy also highlighted that producers of offshore renewable energy are likely to receive reduced revenues in this configuration, with proportionately higher congestion income earned by transmission owners. The Strategy suggests forthcoming EU legislation may provide an option for EU Member States to give a more flexible allocation of congestion income with regard to offshore hybrid projects (also known as MPIs), to ensure that MPI projects are attractive to renewable energy investors[67].

Question 22: Are there any aspects of the priority dispatch and curtailment arrangements, the TCA, or the cross-border trading arrangements that are adopted in UK that might influence the choice of MPI models?

BEIS Question 1: What do you consider to be the key challenges to the establishment and operation of MPIs in the UK presented by current and proposed regulatory requirements applicable in EU Member States or other countries which MPI projects may connect with, or by the TCA? (e.g. regarding the efficient operation of MPIs under both the Home Market and Offshore Bidding Zone approaches). Are there further domestic challenges to these possible market design options

[66] November 2020, [offshore_renewable_energy_strategy.pdf (europa.eu)]

[67] https://ec.europa.eu/energy/topics/renewable-energy/eu-strategy-offshore-renewable-energy_en

Next steps

4.87. This consultation marks the first stage in our process for developing and testing MPI policy options with stakeholders. This work relates closely to BEIS-led activity that explores legislative options for an enduring regime, as well as Ofgem's ICPR, and the ESO's work on early opportunity operating models. These activities are being considered together under the OTNR governance to ensure we take a coherence approach to policy development and stakeholder engagement.

4.88. We will be engaging directly with stakeholders during the consultation window to discuss and explore the issues raised in this consultation. Please do not hesitate to get in touch to let us know if you would like to take part.

4.89. Following this consultation, stakeholder engagement, and further analysis, we intend to signal policy options later in the year. Should we decide to proceed, we will then consult on the implementation of changes to the framework and undertake an Impact Assessments as required.

4.90. Later this year a BEIS-led consultation will be published on a future enduring regime for projects connecting beyond 2030, which will also consider MPIs. If legislative change is pursued for MPIs, amendments will be progressed following this.

Summary of MPI questions

Question 14: Do you think we are focusing on the right models at this stage, or are there other models we should be considering? Is it also necessary to consider the evolution of such MPIs from pre-existing assets? Ultimately, should Ofgem accommodate multiple MPI models (e.g. IC-led and OFTO-led) or just one? What factors influence your answer?

Question 15: Do you agree with this position with regard to ownership structures of MPIs under the current framework?

Question 16: What are the commercial, operational and regulatory factors that would drive a developers preference for either the OFTO-led or IC-led MPI model? and do you envisage a different usage of the component assets of an MPI depending on the MPI model?

Question 17: How would the line to shore (L1) be used in practice and what would you consider to be the primary and secondary activities from a practical perspective? Please provide views for both the IC-led and OFTO-led models, highlighting any differences between L1 usages across the two models.

Question 18: Are there any barriers within the current frameworks, such as definitions within the CUSC, SQSS or other industry codes, that might prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities?

Question 19: What are your views on the feasibility of adopting a regime that requires developers to submit evidence to support their licence application (for assets that form part of an MPI) and commit to regular performance reports? Would this be practicable, proportionate, and effective? Are there other options that work well for industry that we could explore further?

Question 20: What are your views on the practicality of transposing obligations from one licence into another, which obligations would be the most important to incorporate into a remaining licence?

Question 21: Do you think the exemption provision with the Act offers any solutions to licencing MPIs within the current framework, even if only a temporary solution until a potential enduring solution is implemented?

Question 22: Are there any aspects of the priority dispatch and curtailment arrangements, the TCA, or the cross-border trading arrangements that are adopted in UK that might influence the choice of MPI models?

BEIS Question 1: What do you consider to be the key challenges to the establishment and operation of MPIs in the UK presented by current and proposed regulatory requirements applicable in EU Member States or other countries which MPI projects may connect with, or by the TCA? (e.g. regarding the efficient operation of MPIs under both the Home Market and Offshore Bidding Zone approaches). Are there further domestic challenges to these possible market design options

5. Appendices

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Appendix 1 Treatment of AI in Early Opportunities concepts

5.1. This appendix explains how we expect anticipatory investment (AI) to be treated in the six Early Opportunities concepts.

Shared offshore transmission system

Table 6 Treatment of AI in the Early Opportunities concept: Shared offshore transmission system

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
Under the GFAI – single developer approach, the developer of the project making the GFAI holds the AI risk, where it is also the developer of the subsequent project. Where developers are required to do AI work for other developers, we have said that consumers should be protected from increased stranding risk, through user commitment type arrangements and that, subject to the effective management of stranding risk, developers could be given greater confidence on the route to cost recovery for the scope of GFAI undertaken.	AI risk is shared between subsequent project(s) and consumers in proportion to the potential benefit the developer(s) of the subsequent project(s) expect to derive from their project(s). If the benefit associated with the AI will be derived entirely by the subsequent project(s), then the associated AI risk will be allocated entirely to the subsequent project(s) and not to consumers. We would expect: • the contribution from the developer(s) of the subsequent project(s) to be recovered through user commitment type arrangements. Further, we would expect: • the contribution from the developer(s) of the subsequent project(s) to be proportionate to the potential benefit it expects to derive from the infrastructure.

A circuit which connects two (or more) offshore substations that are not connected to a single common substation

Table 7 Treatment of AI in the Early Opportunities concept: A circuit which connects two (or more) offshore substations that are not connected to a single common substation

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
Under the GFAI – single developer approach, the developer of the project making the GFAI holds the AI risk, where it is also the developer of the subsequent project. Where developers are required to do AI work for other developers, we have said that consumers should be protected from increased stranding risk, through user commitment type arrangements and that, subject to the effective management of stranding risk, developers could be given greater confidence on the route to cost recovery for the scope of GFAI undertaken.	AI risk is shared between all project(s) and consumers in proportion to the potential benefit the developer(s) of the project and subsequent project(s) expect to derive from their project(s). We would expect: • the contribution from the developer(s) of the subsequent project(s) to be recovered through user commitment type arrangements. Further, we would expect: • the developer(s) contribution to be proportionate to the potential benefit it expects to derive from the infrastructure.

Multi-purpose interconnector (interconnector led)

Table 8 Treatment of AI in the Early Opportunities concept: Multi-purpose interconnector (interconnector model)

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
There is no reference to AI within the interconnector cost assessment guidance.	AI risk is shared between all project(s) and consumers in proportion to the potential benefit the developer(s) of the project and subsequent project(s) expect to derive from their project(s). We would expect:

	• the contribution from the developer(s) of the subsequent project(s) to be recovered through user commitment type arrangements. • the consumer contribution to be recovered through TNUoS charges. Further, we would expect: • the developer(s) contribution to be proportionate to the potential benefit it expects to derive from the infrastructure.

Multi-purpose interconnector (OFTO led)

Table 9 Treatment of AI in the Early Opportunities concept: Multi-purpose interconnector (OFTO model)

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
Under the GFAI – single developer approach, the developer of the project making the GFAI holds the AI risk, where it is also the developer of the subsequent project. Where developers are required to do AI work for other developers, we have said that consumers should be protected from increased stranding risk, through user commitment type arrangements and that, subject to the effective management of stranding risk, developers could be given greater confidence on the route to cost recovery for the scope of GFAI undertaken.	AI risk is shared between all project(s) and consumers in proportion to the potential benefit the developer(s) of the project and subsequent project(s) expect to derive from their project(s). We would expect: • the contribution from the developer(s) of the subsequent project(s) to be recovered through user commitment type arrangements; and • the consumer contribution to be recovered through TNUoS charges. Further, we would expect: • the developer(s) contribution to be proportionate to the potential benefit it expects to derive from the infrastructure.

Connection of an offshore generator to infrastructure that is located offshore and owned by a Transmission Owner

Table 10 Treatment of AI in the Early Opportunities concept: Connection of an offshore generator to infrastructure that is located offshore and owned by a Transmission Owner

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
Existing price control arrangements such as the Large Onshore Transmission Investments (LOTI) Reopener, and the user commitment methodology set out in CUSC section 15.	No change in treatment.

Connection of electricity storage or a demand user to an offshore transmission system

Table 11 Treatment of AI in the Early Opportunities concept: Connection of electricity storage or a demand user to an offshore transmission system

Treatment of AI under existing framework	Proposed treatment of AI under amended framework
User commitment methodology set out in CUSC section 15.	No change in treatment.

Appendix 2: OTNR Pathway to 2030 Central Design Group final draft Terms of Reference

I. Preamble to the Terms of Reference

- The Terms of Reference (ToR), including the Network Design Objectives, set out in the following document in no way limit the prerogative of Ofgem or the Secretary of State to take decisions in their roles as independent decision makers.
- In particular, neither the ToR nor network designs developed on the basis of the ToR prejudge any decision either:
    - By Ofgem, within the price control framework or on other matters,
    - By the UK Government, in particular BEIS and the Secretary of State, with regard to decisions on Development Consent Orders or on other matters, or
    - By the Scottish and Welsh Governments.
- In developing the Holistic Network Design (HND) and Detailed Network Designs (DNDs) (as described in this document) all parties shall have regard to the existing legal obligations placed upon them, including in particular their licence obligations.
- Ofgem is undertaking a wider Electricity Transmission Networks Planning Review (ETNPR)[68] in parallel to the work of the Central Design Group (CDG). Ofgem will coordinate the ETNPR and OTNR workstreams to ensure that emerging findings align and are compatible as far as possible, to avoid duplication or other process inefficiencies. This will include for example ensuring, as far as possible and appropriate, consistency in analysis and decision-making tools underpinning network plans and designs, as well as roles and responsibilities in developing those plans and designs - with the aim to ensure that the HND and DNDs are compatible with the wider network plans and designs resulting from the ETNPR (eg, through the Network Options Assessment (NOA), the Large Onshore Transmission Investments re-opener or other mechanisms).

[68] The aim of the ETNPR is to ensure that planning and design of the GB electricity transmission network can efficiently support the delivery of net zero at lowest cost to consumers. The ETNPR will review approaches to analysis and decision making, including for anticipatory investment and integration of market solutions, whole system solutions and flexibility to resolve network problems. The ETNPR will also review roles and responsibilities of key parties in early development of solutions, as well as review incentives and legal duties to enable any change. The scope of the ETNPR is broader than the OTNR and any changes to network planning arrangements as a result of the ETNPR may be taken forward after the Central Design Group has produced its initial outputs.

- The ToR and network designs developed on the basis of the ToR are not intended to amend any existing frameworks and obligations (see outputs section on code or licence changes or derogations).
- If the Offshore Transmission Network Review (OTNR) Project Board approves of the ToR, after they have been discussed by the OTNR Expert Advisory Group and the OTNR Working Group, the OTNR Project Board[69] will state its approval and this will be noted in its session minutes, to highlight that the OTNR supports the ToR and the CDG carrying out its works based on the ToR.
- The ToR are only final when the OTNR Project Board has approved of them. However, the CDG can begin work, including stakeholder engagement, in advance of approval.
- Once the HND is completed the Electricity System Operator (ESO), with the support of the CDG members as appropriate, will seek approval of the HND from the OTNR Project Board. This will happen after the design has been discussed by the Expert Advisory Group and the Working Group, and they are satisfied that the recommended design is in line with the requirements of the ToR. The Project Board will state that the HND is in line with the requirements of the ToR and this will be noted in its session minutes, to highlight that the OTNR supports the HND.

[69] For an overview on the OTNR governance fora please refer to slide 9 of this presentation: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/946574/presentation-17-10-20.pdf

II. Terms of Reference for the Central Design Group

A. Governance

1. Purpose

The HND will be delivered by the ESO in consultation with the CDG. The purpose of the HND is to support Government offshore wind targets of 40GW by 2030 for GB, including 11GW by 2030 for Scotland (Scottish Government target) and net-zero by 2050 for GB and by 2045 for Scotland (Scottish Government target).

The purpose of the CDG is to act as a vehicle for the ESO to consult and collaborate with Transmission Owners (TOs) on the HND, and to consult with stakeholder groups as the HND is developed.

2. Objective

The ESO, in consultation with the CDG, will deliver an HND that ensures an economic, efficient, operable, sustainable and coordinated National Electricity Transmission System (NETS) (including onshore and offshore assets required to connect offshore wind) to present options and a recommended HND for offshore connections works. This includes connections and associated strategic onshore infrastructure necessary to connect offshore generation in order to facilitate the pace and certainty required to deliver the 2030 offshore wind targets and the 2045 and 2050 net zero targets.

Through considering the requirements for the NETS holistically, the HND should seek to minimise the amount of infrastructure and the number of landing points (ie, the point infrastructure makes landfall), compared to the current individual point-to-point approach to offshore connections. It should also, in a balanced way, seek to reduce costs to consumers and impacts on the environment and local communities.

There are two parts of network design for both onshore and offshore as further described in Part B and Part C:

- HND, and
- DND

3. Inputs

A non-exhaustive list of inputs for the HND are listed below.

- Generation Map
- NG ESO 2021 Future Energy Scenario (FES) elements that meet net zero targets for 40GW of OFW by 2030 and meet future net zero targets
- NOA January 2021 infrastructure assumptions against 2020 FES leading the way analysis
- The Network Design Objectives (see below section E) for the HND
- TCE East Coast Spatial Grid Study and Marine Scotland Sectoral Plan
- Inputs from other stakeholders (including environmental stakeholders) to contribute to the overall CDG objective
- Cost Benefit Analysis (CBA) methodology to reflect objectives and (as far as is appropriate) consistent with existing arrangements, eg NOA
- Industry technical and commercial codes and standards
- Existing network design rules based on the Security and Quality of Supply Standards (SQSS) to guide the HND.

4. Output

- Recommended HND, including any notable HND variations
- Proposed network design rules based on the Security and Quality of Supply Standards (SQSS) to guide the HND
- Recommended changes to industry technical and commercial codes, standards and licence, or derogations the CDG considers are required in respect of the HND and proposals. This could include the trialling of any innovative approaches pending changes or derogations.

5. Logistics

- The CDG meets at appropriate frequency to deliver outputs by agreed deadlines.
- The CDG can decide to form sub-groups as appropriate; sub-group governance should be consistent with the CDG’s governance.
- Options for virtual attendance will be available for all sessions.

6. Membership and attendees

Members:

- Representatives of the ESO, NGET, SSEN-T, SPEN
- Parties responsible for delivery of offshore infrastructure once known

Observers:

- BEIS and Ofgem representatives
- Representatives of the Devolved Administrations

Guests: The CDG can invite guests (including in-scope developers such as those that have secured seabed leases through the Crown Estate Round 4 and ScotWind leasing rounds) on a case-by-case basis to provide input on specific topics.

The ESO will chair and provide a secretariat function for the meetings.

7. Delegates

Delegates must have appropriate authority to speak on behalf of their organisation.

B. OTNR HND

1. Scope of work

a. HND timing

The ESO will deliver the final draft of the HND in January 2022, in consultation with the CDG.

b. HND content

- The HND must identify the requirements for network capacity on the NETS across GB and in offshore waters.

- The HND should as far as reasonably possible include indications on the potential location of infrastructure such as onshore landing points and locations of new substations, as well as technology type (eg AC vs. DC) and other key parts of the specification. It should provide developers with potential connection points and connection dates. Two additional points should be considered as part of this development:

- First, the HND should include a robust CBA of the different options available. Noting the NOA and other CBA methodologies, the CDG will need to determine an appropriate CBA methodology against which to assess identified options.

    - In practice, the HND will cover the appropriate onshore and offshore network. This includes the interface between what is currently considered the 'offshore' network (assets operated by an Offshore Transmission Owner today) and 'onshore' network (assets operated by a TO today).

    - For those elements of the HND on the 'offshore' side of this interface, the HND should provide as much detail as reasonably possible, while considering that the DND will then set out the next level of detail (see below), in terms of both the electrical and spatial configuration of assets. A robust CBA should be applied cognisant of, and consistent with the RIIO-T2 price control frameworks.

    - For those assets on the onshore side of the interface, any element of the HND (and subsequent DND) that includes infrastructure that would typically form part of a future NOA should take its NOA treatment into consideration and the ESO should take reasonable steps that, while remaining consistent with the Network Design Objectives, HND proposals and the outcome of the NOA align and where this is not the case the differences are justified.

    - The associated assets would be subject to the relevant existing regulatory processes within the RIIO-2 price control). In order to facilitate the consideration of those assets in a timely and efficient manner, the HND should therefore provide information (eg electrical and spatial configurations, CBA) to the form and standard that would normally be expected under eg the relevant regulatory process.

- Second, the HND needs to consider cost along with environmental and other considerations.

- In developing the HND the ESO (in its independent role including in relation to and within the CDG) should seek to minimise the whole system cost to the consumer of the NETS while also meeting network planning and operational standards. The ESO should also take into account the Network Design Objectives, but taking due consideration that the HND needs to be an economic and efficient solution. Whole system costs must account for achieving the Government's net zero targets, while appropriately managing social, environmental and economic impacts to ensure clean, green, affordable and reliable energy to the consumer. Where a different balance of Network Design Objectives (in particular of total cost vs. other objectives) would result in a very different HND, the ESO should make this clear as part of the recommendation process and if appropriate show alternative options.

- The HND should provide a sufficient level of detail to allow the parties undertaking the DND to make decisions about the specific Network Assets that would fulfil the requirements of the HND. The HND should include a number of "fixed" design components, but it should not limit the ability of the parties undertaking the DND to exercise their engineering judgement or limit their ability to discharge their detailed planning and consenting obligations.

c. Roles and responsibilities for the HND development

- The ESO will be responsible for making an independent evaluation of the HND, including carrying out the CBA
- The ESO will be responsible for developing, delivering and owning the HND.
- However, in developing the HND the ESO should work closely with the TOs and, if this is decided in time, the party responsible for delivery of the offshore DND, and take into account their views.
- If there is a divergence in opinion the ESO, the TOs and the other members of the CDG will seek to find agreement. If an agreement cannot be found, the ESO will take the final decision.
- The CDG should also take into account the views of developers and, as already stipulated by individual licences, environmental and community stakeholders, as far as is appropriate and reasonably practicable. This will include spatial planning, indicating where there are environmental constraints, land availability and interactions with other assets (including those not owned by TOs). In both cases the ESO should be able to demonstrate how those parties' views have been addressed within the final HND.

C. OTNR DND

1. Scope of work

- The DNDs for both offshore and associated onshore assets should set out the next level of detail for the Network Assets based on the requirements set out in the HND. The DND should also seek to address the key environmental and cumulative impacts indicated in the HND and therefore include mitigations, as applicable.

    - The onshore DND should be at a level of detail that allows licensees to proceed with the delivery of Network Assets, such as the pre-consenting development phase and detailed technical studies.
    - Where the TO is progressing development of the infrastructure the DND should be of a level that allows the TO to make a submission to the appropriate RIIO-T2 mechanisms. If the TO thinks it will need to make a submission to trigger an uncertainty mechanism to build the respective piece of infrastructure, it should also provide an early indication of this to Ofgem.
    - The TOs will undertake the onshore DND in their respective Licence Areas.

  It is hereby noted that some of the onshore infrastructure that will feature in the HND is already in the DND phase.

D. Interpretation

For the purposes of this document:

- Licence Area has the meaning given to it in the Electricity Transmission Licence.
- National Electricity Transmission System (NETS) has the meaning given to it in the standard conditions of the Electricity Transmission Licence.
- Network Assets has the meaning given to it in the Electricity Transmission Licence.
- Network Design Objectives are the ones listed in section E of this document.

E. Network Design Objectives

#	Name	Description	Notes
1	Economic and efficient costs	Network solution is economic and efficient	• Taking into account, amongst others, whole system costs and the requirements of licence obligations. • Least regrets investment decision that can be taken 'today', ie, reinforcements that are required under all FES that are in optioneering to consultation stage in 2021 to meet a 2030 delivery.
2	Deliverability and operability	Network solution is deliverable by 2030 and the resulting system is safe, reliable and operable	• The aim is that the coordinated onshore and offshore network infrastructure connects the Leasing Round 4 and ScotWind projects by 2030 consistent with achieving Government offshore wind targets of 40GW by 2030 for GB, including 11GW by 2030 for Scotland, while protecting system security, reliability and resilience. • Also, recommend reinforcements to manage constraints that are consistent with the Network Design Objectives. • Taking into account, amongst others, planning consent requirements, value for money to the consumer and commercial acceptability from developers. • This objective likely interacts with environmental impact and community impact.
3	Environmental impact	Environmental impacts are avoided, minimised or mitigated by the network design, and best practice in environmental management is incorporated in the network design	• Cumulative environmental impacts of the design should be considered in addition to impacts in isolation, ie, a high-level desktop assessment of key environmental impacts should be undertaken. • Includes offshore and onshore environmental impacts, for example AONB, SSSI and marine constraints. • Avoided carbon emissions should be considered through the connection of low carbon generation vs. fossil fuels.
4	Local communities impact	Local communities impacts are avoided, minimised or mitigated by the network design	• Encompasses onshore and offshore communities, and wider onshore communities hosting strategic grid infrastructure. • Addressing the concerns of local communities which typically relate to: The number and size of onshore connection points and onshore infrastructure; cumulative impacts associated with multiple connections, substations and other infrastructure; onshore transmission reinforcements driven by offshore infrastructure connections. Co-ordinated/ consolidated/ integrated infrastructure is central to mitigating impacts.

Appendix 3 Policy Assessment Criteria

- Purpose is to a) translate policy aims of the review into specific set of criteria for policy options and b) provide a common way of considering and comparing options within a workstream, subject to resourcing proportionality and consistency with relevant public bodies' strategic aims and statutory duties

- Intend to use the same criteria for all workstreams and include interactions between the workstreams where necessary.

- In general, our approach to assessment will be consistent with prevailing good practice, for example the Green Book and Impact Assessment guidance where relevant

- We do not intend to numerically weight criteria, and a balance will need to be struck by decision makers. Some criteria may be more important in one workstream than another.

- Criteria are intended for evaluating policy choices (eg high level design of enduring regime, delivery options for pathway to 2030), not for detailed economic/engineering decisions at specific sites (eg placing a cable route from A to B or A to C).

- Initially they will be used largely qualitatively, with an expectation of more detailed quantitative work when appropriate for specific workstreams

- All options compared to **baseline of uncoordinated point to point solutions** for each site. An uncoordinated solution for the purposes of this pack means a connection provided as per industry processes and requirements as they had effect on 13 January 2021. The descriptions used by the ESO for 'integrated' and 'status quo' models will be used to support options assessments where appropriate. Please refer to the ESO Phase 1 Report, page 17, Table 1. Ref: download (nationalgrideso.com)

- They are a tool for aiding decision making. They are intended to be consistent with relevant wider objectives (such as the 10 point plan and offshore wind supply chain) and duties (such as Ofgem's statutory duties). They are not intended, in themselves, to set policy or minimum standards, for example in respect to environmental requirements. It is for the relevant decision making authority to utilise the results of our assessments when making decisions in accordance with its objectives and duties.

1. Deliverability of OTNR policy and Net Zero			
#	**Name**	**Description**	**Notes**
1a	Deliverability	Policy can be delivered in a timely and proportional fashion for the workstream	• Two aspects to this – delivery of policy/regulatory change, and deliverability of the policy option (for the transmission infrastructure itself and users connecting into it) • Not a binary answer – ability to deliver is dependent on several factors including organisations involved, scope and timeline • Qualitative assessment – is it even possible to make these changes (policy change, regulatory change, industry governance), and to do so sufficiently quickly? • Is the delivery model, overall regime, and timing feasible given other constraints, eg technology readiness, onshore network reinforcement, environmental legislation? • Qualitative assessment – can it be done in time to affect the projects it intends to? How complex is the change? • Is the development process sufficiently simple that developers/stakeholders can understand, navigate and use it in practice?
1b	Decarbonisation	Supports decarbonisation/NZ agenda ie total/speed of emissions reduction	• Option must support the achievement of net zero greenhouse gas emissions • Carbon impact of transmission infrastructure, plus link to deployment impact, and may impact curtailment • Does it enable 40GW of offshore wind by 2030? • Does it help or hinder other potential offshore technologies eg hydrogen, CCUS

2. Economics and commercials			
#	**Name**	**Description**	**Notes**
2a	Deployment impact	It speeds up deployment of offshore wind compared to an uncoordinated solution	• Could deployment be sped up through a coordinated approach to grid connection? Could it also reduce or increase (risk of) delays through planning and consenting? • Integrated solution may delay some as they 'wait' for it, but speed up others if it gives a ready made route to shore (eg prior to getting seabed lease) • Combining some process steps (or streamlining) may speed up whole development process • Deployment impacts may also include cost-effectiveness, safety (in terms of safety and integrity of system eg reliability), flexibility (does it lock in design/tech earlier or later than current regime?)

2b	Renewable generation competition impact	Maintain an effective competitive regime and level playing field for different actors in renewable generation	• OSW competition (eg increased or decreased by certain types of process integration) • Minimise competitive distortions (eg in CfD bid, in bearing costs of AI, timing and delays impact) • Maintain an effective competitive regime and level playing field for different actors • Note that potential for reform (eg of CfD, of market) can increase complexity and uncertainty, which may be detrimental to competition • Impact on competition is on a spectrum, not a binary outcome
2c	Transmission competition impacts	Increases, or does not decrease or distort, competition in transmission	• Delivery model for shared/coordinated transmission infrastructure may impact competition. For example, a model with less competition than current regime may be preferred if it enables other aims such as speed of deployment. Equally other models may increase competition, such as earlier-stage competition for offshore transmission infrastructure. • Potential knock-on impacts on onshore reinforcement and CATO regime • How the model makes sure parties involved in transmission have the skills and capabilities to deliver • Impact on competition is on a spectrum, not a binary outcome
2d	Risk allocation	Places risks on those best placed to manage them	• Is risk being placed with those best able to manage it? Is risk being allocated fairly? • Does the policy option materially increase/decrease project delivery risk? Eg by how it impacts liabilities, control etc. Including who bears the risk (and associated financial impact to transmission owner, generators and other transmission users) of delays in completion of transmission infrastructure. One way these risks manifest is through the FID for generation and transmission • ‘Project’ here can refer to offshore wind, offshore transmission or interconnectors (or other variants and technologies where appropriate) • Risks include but are not limited to delays, costs, decommissioning • Level of clarity and transparency for who bears risk

3. Environmental and Societal Impact			
#	**Name**	**Description**	**Notes**
3a	Environmental (non-carbon) impact	Significant impacts on the environment are avoided, minimised or mitigated by coordinated transmission	• Includes offshore and onshore environmental impacts, for example AONB, SSI. • Reduced volume of assets but remainder are larger in size and may involve more ‘crossings’ of other infra assets • Marine constraints per TCE study – biodiversity, physical environment, historical environment, other subsea/infra, • When applying these criteria in practice, consideration must be given to the impact on Marine Protected Areas (MPAs) in order to minimise adverse impacts that might

			later risk or delay consent." We note a number of requirements flowing from legislation (eg habitats regulations, Marine and Coastal Access Act) must be factored into any policy framework. •Regional environmental impacts (eg peatland in Scotland) •Cable impacts can include cable installation, sandwave clearance, external cable protection impacts,
3b	Local Communities Impact	Impact and mitigation on local (including coastal) communities impacted by construction of 'onshore' assets and related activity	• Encompasses onshore and offshore communities, including sea users (such as fishing) and wider onshore communities hosting strategic grid infrastructure • Potential benefits including job creation, utilisation of local supply chains, and impact of compensatory measures • Key concerns typically relate to: the number and size of onshore connection points and onshore infrastructure; cumulative impacts associated with multiple connections, substations and other infrastructure; onshore transmission reinforcements driven by offshore infrastructure connections; and the lack of co-ordination between wind farm proposals. Co-ordinated/ consolidated/ integrated infrastructure is central to mitigating impacts. • Concerns about impacts relate to: visual impact; proximity to residential areas (socio-economic impacts) and built environment impacts (including heritage/ listed building impacts); impacts on environmentally protected and/or sensitive areas (ecological and visual impacts); lack of use of brownfield sites (use of which could be mitigation); noise, traffic and transport during construction in particular; additional local socio-economic and tourism impacts, particularly during construction.

4. Consumer and system impact			
#	**Name**	**Description**	**Notes**
4a	End-consumer net benefit	Has a positive impact on consumer savings	• Consumer savings (or additional costs), most notably through lower offshore T costs and hence lower CfD pricing (or market pricing eg cPPA), but also wider savings/costs. • Note that in principle impacts such as impact on onshore investment, curtailment, balancing costs, financing costs (ie WACC) could be factored into this analysis as part of a Cost-Benefit Analysis. In practice a proportionate approach must be taken in the time available. • Anticipatory Investment risk could be borne by the end-consumer - cost where any investment is not needed (either temporarily or permanently) • Note may also be non-monetary impact to all GB consumers of a more/less reliable network.

Appendix 4 Case study of Kriegers Flak MPI

Case study of Kriegers Flak MPI

5.1. This EU case study provides a useful reference for stakeholders in understanding the concept of an MPI as well as the benefits and challenges they face in becoming operational in the current legal and regulatory frameworks across EU.

5.2. Kriegers Flak (KF) is a Combined Grid Solution (CGS) "hybrid project" (or MPI for the purposes of this consultation) connecting offshore wind farms in Danish and German jurisdiction, which began operation in 2020. It relies on a derogation[70] (provided for by Article 64) from various articles of the EU's Electricity Regulation, including Article 16, for a time-limited period for situations where "the Member State can demonstrate that there are substantial problems for the operation of small isolated systems and small connected systems".

5.3. Article 16(8) of the EU's Electricity Regulation states that the volume of interconnection capacity made available to market participants shall not be limited, with a minimum level of 70% of capacity available for cross-zonal trade. Article 16(9) provides for short derogations from this requirement (up to a maximum of two years) for operational security. Article 64 provides for derogation from Article 16, for a time-limited period for situations where "the Member State can demonstrate that there are substantial problems for the operation of small isolated systems and small connected systems". Such a derogation now applies to the Kriegers-Flak Combined Grid Solution.

5.4. Kriegers Flak comprises a new offshore wind farm, and together with the two existing wind farms (Baltic 1 and Baltic 2) forms the project. The project was undertaken by the German Transmission System Operator (TSO) 50Hertz Transmission[71] and the Danish TSO Energinet. It was co-financed by the European Union. Construction work began in 2017 and the solution became operational in December 2020.

[70] L_2020426EN.01003501.xml (europa.eu)
[71] 50Hertz operates the electricity transmission system in the north and east of Germany. Source: This is 50Hertz

5.5. The new system is the first of its kind and will enable the exchange of electricity between the two countries by using existing and new connections between the wind farms. The benefits of the system are that it transports energy generated from the wind farms, but also increases system stability and security of supply. When there is no wind, or light wind, the subsea cables will be used to exchange electricity between the two countries. This maximises utilisation of the infrastructure and ensures better value for consumers.

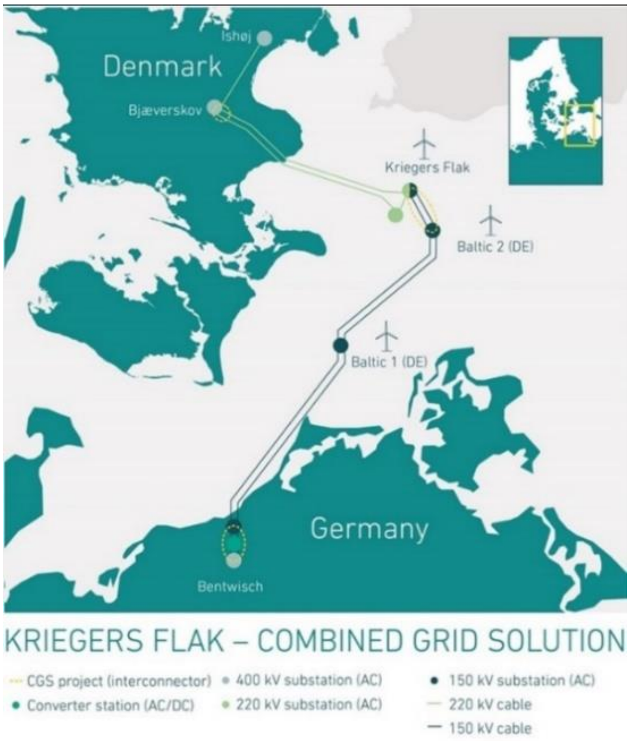

Figure 15 Illustration of the Kriegers Flak Combined Grid Solution project

5.6. Germany and Denmark have different regulatory environments and this has brought challenges related to having two national TSOs as equal partners in the execution and operation of the KF system. This has been addressed by each TSO having a 50% ownership of the assets[72].

5.7. In July 2020, the Danish and German authorities submitted to the European Commission a request for derogation of the KF project to be exempt from Article 16(8) of the Electricity Regulation. The Article requires that at least 70% of the total IC transmission capacity must be made available for cross border trades. The two nations requested that the minimum percentage should not apply to the overall transmission capacity respecting operational security limits after deduction of contingencies, but rather that it should apply only to the capacity remaining after all capacity expected to be required for the transmission of production from the wind farms connected to the system to shore has been deducted. The granted derogation is applicable for 10 years, and, though it may be prolonged, the total duration of the derogation, including any prolongations, shall not exceed 25 years. As the wind farms are not formally part of the KF project, the derogation request is only applied to assets involving the exchange of electricity between the two countries.

[72] energinet-kriegers-flak-lessons-learned.pdf (windeurope.org)

5.8. A key reason for the derogation request was because if the price in the German bidding zone (DE/LU) was higher than the price in the Danish bidding zone (DK2), the connection cable between the German wind farms and the German shore would be congested ie electricity flowing from the German wind farms to the German market due to price signals. Thus, ensuring a minimum trade volume on this cable would require countertrading in the direction DE/LU (Germany) towards DK (Denmark). If, in such a situation, at least 70% of the 400 MW capacity (thus 280 MW) were to be made available for trade, this capacity would be used for flowing electricity from the DK2 zone (Danish zone) to the DE/LU zone (German zone). However, the addition of the 280 MW and the wind from the Baltic 1 and Baltic 2 wind farms, which are located in the DE/LU bidding zone, would exceed the capacity of the connection cable between those wind farms and the German shore.

5.9. The European Commission (EC) concluded that a full application of Article 16(8) to the KF project system would create substantial problems and therefore granted that the 70% minimum should be calculated on the residual capacity after deduction of the capacity necessary for transporting the forecasted (day ahead) electricity production by the three wind farms[73]. This derogation is initially applicable for 10 years but a prolongation can be requested.

[73] L_2020426EN.01003501.xml (europa.eu)

Appendix 5: Glossary

A

Anticipatory investment (AI)

Investment that goes beyond the needs of immediate generation, reflecting the needs created by a likely future generation project or projects.

Authority

The Gas and Electricity Markets Authority established by section 1(1) of the Utilities Act 2000. The Authority governs Ofgem.

B

BEIS

Department for Business, Energy & Industrial Strategy

C

CBA

Cost benefit analysis

CDG

Central design group, formed by ESO and the TOs to support the production of the HND within the scope of the Pathway to 2030 workstream.Central design group formed by the ESO and the TOs to support the production of the HND within the scope of the Pathway to 2030 workstream.

CES

Crown Estate Scotland

CfD

Contract for Difference

CUSC

Connection and Use of System Code

D

Developer

The Tender Regulations define a 'developer' as 'any person within section 6D(2)(a) of the Electricity Act 1989'. Section 6D(2)(a) of the Electricity Act defines such person as 'the person who made the connection request for the purposes of which the tender exercise has been, is being or is to be, held'. In practice, such person is also the entity responsible for the construction of the generation assets and, under Generator Build, the Transmission Assets. In this document, 'Developer' is also used to refer to developers of electricity interconnectors.

E

Electricity Act or the Act

The Electricity Act 1989 as amended from time to time.

ESO

Electricity System Operator

F

Final Transfer Value (FTV)

The final transfer value set by Ofgem in accordance with the OFTO Cost Assessment Guidance.

G

Generator Build

A model for the construction of Transmission Assets. Under this model, the Developer carries out the preliminary works, procurement and construction of the Transmission Assets.

GFAI

Generator focussed anticipatory investment

H

HND

Holistic network design, which will identify the requirements for network capacity on the NETS across GB onshore and in offshore waters to efficiently connect projects within the scope of the Pathway to 2030 workstream.

I

Interconnector Cost Assessment Guidance
Guidance document that sets out the processes that we follow whilst undertaking the cost assessments of electricity interconnectors.

Interconnector Licence
A licence authorising a person to participate in the operation of an electricity interconnector.

ITPR
Integrated Transmission Planning and Regulation

N

NETS
National Electricity Transmission System

NOA
Network Options Assessment

O

Ofgem
Office of Gas and Electricity Markets. Ofgem, “the Authority” and “we” are used interchangeably in this document.

OFTO
Offshore transmission owner

OFTO Build
A model for the construction of Transmission Assets. Under this model, Ofgem runs a tender to appoint an OFTO with responsibility for constructing and operating the transmission assets.

OFTO Cost Assessment Guidance
Guidance document that sets out the cost assessment process that Ofgem follows to determine the transfer value for an offshore transmission system.

OFTO Licence

The licence awarded under section 6(1)(b) of the Electricity Act following a tender exercise authorising an OFTO to participate in the transmission of electricity in respect of the relevant Transmission Assets. The licence sets out an OFTO's rights and obligations as the offshore transmission asset owner and operator.

R

RIIO-ET2

The network price control which sets out what the electricity transmission network companies are expected to deliver for energy consumers from 2021-2026.

T

TCE

The Crown Estate

Tender Process

The competitive tender process run by Ofgem in accordance with the Tender Regulations in order to identify a successful bidder to whom a particular OFTO Licence is to be granted.

Tender Regulations

Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015.

Tender Revenue Stream (TRS)

The payment an OFTO receives over its revenue term.

TO or Transmission Owner

An owner of a high-voltage transmission network or asset.

ToRs

Terms of reference, to clarify the network design objectives of the Pathway to 2030 workstream.

Transmission Assets

Transmission assets are defined in Paragraph 1(3)(a) of Schedule 2A to the Electricity Act as 'the transmission system in respect of which the offshore transmission licence is (or is to be) granted or anything which forms part of that system'. The transmission system is expected to include subsea export cables, onshore export cables, onshore and offshore substation, and any other assets, consents, property arrangements or permits required by an incoming OFTO in order for it to fulfil its obligations as a transmission operator.

TNUoS

Transmission network use of system. TNUoS charging arrangements reflect the cost of building, operating and maintaining the transmission system.

W

WNBI

Wider network benefit investment

Appendix 6: Consolidated consultation questions

Early Opportunities questions

Question 1: Are there any concepts we have not identified developers (as defined in this chapter) may wish to progress?

Question 2: Should anticipatory investment risk be shared with consumers? If it should, what level of risk is it appropriate for consumers to bear?

Question 3: For concepts that intended to provide a wider system benefit, eg by mitigating an onshore constraint, how should the need for investment be demonstrated by the developer?

Question 4: What options are available to developers in demonstrating a reasonable expectation they intend to connect to the system?

Question 5: To what extent do you agree with out proposals to remove barriers to the Early Opportunity concepts? Please explain your answer.

Question 6: Do you believe a Significant Code Review is required to give effect to a potential decision to 'share' AI risk between consumers and developers?

Question 7: Do you agree with Ofgem's proposed approach to deliver the objectives of Early Opportunities workstream?

Pathway to 2030 questions

Question 8: We consider that a holistic design will result in a more coordinated, economic and efficient network. Do you agree? Please give reasons for your answer.

Question 9: Do you agree with the planned work for a detailed network design offshore?

Question 10: Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

Question 11: Do you agree that the existing developer led model should be retained and applied where the HND indicates a radial solution should be used? Please explain your answer.

Question 12: Please provide your views on each of the delivery options we have described in this document. In providing your views, please comment on the issues we have raised. Please also give your views on the implementation issues we have raised.

Question 13: Please describe any feasible delivery options that we have not set out in this document.

MPI questions

Question 14: Do you think we are focusing on the right models at this stage, or are there other models we should be considering? Is it also necessary to consider the evolution of such MPIs from pre-existing assets? Ultimately, should Ofgem accommodate multiple MPI models (eg IC-led and OFTO-led) or just one? What factors influence your answer?

Question 15: Do you agree with this position with regard to ownership structures of MPIs under the current framework?

Question 16: What are the commercial, operational and regulatory factors that would drive a developers preference for either the OFTO-led or IC-led MPI model? and do you envisage a different usage of the component assets of an MPI depending on the MPI model?

Question 17: How would the line to shore (L1) be used in practice and what would you consider to be the primary and secondary activities from a practical perspective? Please provide views for both the IC-led and OFTO-led models, highlighting any differences between L1 usages across the two models.

Question 18: Are there any barriers within the current frameworks, such as definitions within the CUSC, SQSS or other industry codes, that might prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities?

Question 19: What are your views on the feasibility of adopting a regime that requires developers to submit evidence to support their licence application (for assets that form part of an MPI) and commit to regular performance reports? Would this be practicable, proportionate, and effective? Are there other options that work well for industry that we could explore further?

Question 20: What are your views on the practicality of transposing obligations from one licence into another, which obligations would be the most important to incorporate into a remaining licence?

Question 21: Do you think the exemption provision with the Act offers any solutions to licencing MPIs within the current framework, even if only a temporary solution until a potential enduring solution is implemented?

Question 22: Are there any aspects of the priority dispatch and curtailment arrangements, the TCA, or the cross-border trading arrangements that are adopted in UK that might influence the choice of MPI models?

BEIS Question 1: What do you consider to be the key challenges to the establishment and operation of MPIs in the UK presented by current and proposed regulatory requirements applicable in EU Member States or other countries which MPI projects may connect with, or by the TCA? (eg regarding the efficient operation of MPIs under both the Home Market and Offshore Bidding Zone approaches). Are there further domestic challenges to these possible market design options