Additional draft impact assessment

Additional draft impact assessment on Pathway to 2030 workstream's minded-to decision on the Delivery Model option			
Division:	Networks	**Type of measure:**	Competition in Offshore Transmission Networks
Team:	Offshore Coordination	**Type of IA:**	Qualified under Section 5A UA 2000
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Coverage:	Full		

Summary

This document is an additional draft impact assessment that sets out an assessment of our revised minded-to decision for the delivery model developed through the Offshore Transmission Network Review (**OTNR**) Pathway to 2030 (**PT2030**) workstream.[1] This assessment highlights changes to the quantified costs and benefits estimated in the first draft impact assessment and the implications of these changes. This additional draft impact assessment considers an expanded package of options for the delivery of coordinated non-radial assets and compares them against the options in the original minded-to decision.

What is the problem under consideration? Why is Ofgem intervention necessary?

The current frameworks relating to developing and connecting offshore wind generation are being reviewed in light of the government's ambition for offshore wind. In 2019, the government stated[2] its ambition of achieving a significant increase, to 40GW in offshore wind capacity by 2030, from the current level of around 10GW. In April 2022, the then Prime Minister announced a new British Energy Security Strategy (**BESS**), which built on previous offshore wind targets, increasing offshore wind capacity to 50GW by 2030.[3] We do not consider that individual radial offshore transmission links[4] for this amount of offshore wind generation are likely to be economical, appropriate or acceptable for consumers, local communities or the environment.

The objective of the OTNR is to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, whilst considering the increased ambition for offshore wind to achieve net zero. The OTNR aims to ensure that future connections for offshore wind are delivered with increased coordination whilst ensuring an appropriate balance between environmental, social and economic costs. The OTNR is now transitioning from reviewing to reforming, as we publish decisions and begin to implement the regulatory and planning changes necessary to deliver a coordinated offshore transmission network.

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[1] Revised minded-to decision to expand the choices available to developers in the delivery of non-radial offshore transmission assets
[2] Queen's_speech_December_2019_background_briefing_notes (publishing.service.gov.uk)
[3] British Energy Security Strategy (publishing.service.gov.uk)
[4] To date, offshore windfarms in GB have been connected to the shore via standalone radial transmission links. With more offshore windfarm projects planned, many of which are further from shore than those developed already, there is potential for efficiencies from greater coordination of offshore transmission infrastructure.

May 2022 minded-to decision and first draft impact assessment

Our minded-to decision and further consultation on PT2030[5], hereafter known as our May 2022 publication, considered seven delivery model options, comprising of various actors designing, consenting, building and owning the non-radial offshore transmission assets. The options also included different competition models: early, late, very late and no competition.

In the May 2022 publication, we explained our intention to adopt a 'very late (post-construction) competition generator build' model for non-radial offshore transmission in scope of PT2030. Under this model, generators deliver and construct the assets before they are tendered. The competition only focuses on financing, operation and maintenance. We considered this model to be the best option to deliver on the coordinated offshore transmission assets required to achieve the government's offshore wind generation targets, at a reasonable cost to consumers and in the timeframe available.

Our quantitative analysis supported the May 2022 publication's minded-to decision. We estimated that one year of delay, load factor depending, would cost between £1,116m and £1,464m. Three years of delay would cost between £3,209m and £3,975m. We contrasted these delay costs with potential cost savings brought on by varying competition models.

Workstream progress, Holistic Network design and asset classification

Based on consultation responses and feedback, we have decided to revisit the May 2022 publication for the PT2030 non-radial delivery model. We have also revised some of our earlier figures, now that the Holistic Network Design (**HND**)[6] has been published and the asset classification process has been finalised. The revised minded-to decision now includes the extension of the anticipatory investment (**AI**) policy from the Early Opportunities workstream. It also includes the option for developers to choose a late competition Offshore Transmission Owner (**OFTO**) build model, for non-radial assets, along with our original option for very late competition generator build model.

The HND, together with the asset classification process, resulted in significantly fewer non-radial assets than we had assumed in our first draft impact assessment.[7] By applying our classification process to the HND, it has resulted in six onshore, twelve radial offshore

[5] Minded-to Decision and further consultation on Pathway to 2030 | Ofgem
[6] Pathway to 2030 Holistic Network Design summary report
[7] Offshore Transmission Network Review: Decision on asset classification | Ofgem

transmission and three non-radial offshore transmission assets. Non-radial transmission assets (5,400MW) comprised 15% of the total HND transmission assets (35,890MW). The lower number of non-radial transmission assets has led us to revisit the figures and assumptions that underpinned the first draft impact assessment. The HND Follow-up Exercise (**HNDFUE**)[8] is underway and it will include a further 16.9GW from ScotWind tranche two and an estimated 3GW from the Celtic Sea leasing round. The asset classification process will apply to the HNDFUE.[9]

Feedback informing our revised minded-to decision

We received 29 responses to the May 2022 publication which showed a mixed response. Section 3 of the consultation document summarises the feedback received. The feedback included a request for further clarity on the application of AI policies to the projects within the scope of the PT2030 workstream and the inclusion of additional options for developing coordinated assets. Our revised minded-to decision now gives developers the option of:

- working collaboratively with other developers using a very late competition generator build model (our original minded-to position); **or**
- using the very late competition generator build model which includes the extended AI policy; **or**
- using a late competition OFTO build model for the non-radial transmission assets in scope of the workstream.

What are the policy objectives and intended effects, including on Ofgem's Strategic Outcomes?

Ofgem is a key delivery partner of the OTNR. The objective of the PT2030 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. The workstream also captures one project from an earlier leasing round and will now include the Celtic Sea leasing round. Further discussion on the projects included in the scope of this revised minded-to decision has been included in the accompanying consultation document.

[8] OTNR Pathway to 2030 Central Design Group and Network Design Terms of Reference for development of the follow-up Holistic Network Design and follow-up Detailed Network Designs
[9] This ScotWind tranche two capacity (16.9GW) includes the ScotWind clearing round.

What are the policy options that have been considered, including any alternatives to regulation?

This additional draft impact assessment considers our revised minded-to decision of giving developers the choice between the very late competition generator build and late competition OFTO build models. We also consider the extension of AI policy from the Early Opportunities workstream to projects in scope of the PT2030 workstream. We compare this 'expanded package' with the May 2022 publication in which developers only utilise the very late competition generator build model. Since the publication of the HND and the application of the asset classification process, we have revised our assumptions and used these for the expanded options we are now considering. The expanded package of options now forms our preferred option.

Preferred option - Monetised Impacts (£m)

Business Impact Target Qualifying Provision	Non-qualifying (competition)
Business Impact Target (EANDCB)	Not relevant
Net Benefit to GB Consumer	See below
Wider Benefits/Costs for Society	Significant benefits

Explain how the Net Benefit was monetised, NPV or other (*NPV calculated using 2022 as base year. Economic costs and benefits are in 2022 financial year prices covering the period from 2031 to 2032*).

In our first draft impact assessment, we excluded delivery models partially due to their potential delay costs. In the first draft impact assessment, we estimated that the proposed very late competition generator build model scenario would not lead to delays.

In response to the May 2022 publication, respondents indicated that developers could struggle to coordinate without the extension of the AI policy and the right delivery model optionality. Without the AI policy extension, respondents noted that developers could be drawn into lengthy formal cooperation negotiations causing the projects to be delayed beyond the 2030 target. Additional complexity could be caused if two projects are on different timescales and the AI policy is not extended to facilitate co-development.

Some respondents also expressed their desire to have a generator designed, late competition OFTO build model as an option for non-radial transmission assets. The late competition OFTO build model was seen as an option to provide a route to delivery. OFTO build could be used, for example, in cases where developers cannot reach independent commercial agreements with each other or AI policy-based solutions to deliver coordinated assets. The lack of adequate optionality with regards to delivery options can increase the risk of non-delivery of coordinated assets.

We consider that our revised position helps avoid a one-to-two-year delay. We assess a one-year delay to be likely and two-year delay to be somewhat likely. The revised position, with the expanded options available to developers, helps developers avoid these delays when delivering coordinated assets. The expanded options help developers avoid lengthy negotiations involved with formal cooperation agreements.

We recognise that a risk of delay under one of the options (a late competition OFTO build) still exists. However, we consider this option to effectively mitigate against the risk of non-delivery by providing more optionality and flexibility to suit project-specific circumstances.

The number of non-radial transmission assets is smaller than expected. This reduces the aggregate cost associated with any delays. After the publication of the HND and the application of the asset classification process, the non-radial transmission assets account

for 5.4GW of capacity. The first year of delay in terms of discounted carbon cost is now estimated at £147m-237m and two years is estimated at £267-429m. The first year of delay in terms of discounted option fees costs is estimated at £351m and cumulative two years at £679m. In total, if the options are not expanded and developers face a one-to-two-year delay, we estimate a delay cost to range from £499-588m and £946-1,108m respectively.

We do not have concrete estimates on the number of non-radial transmission assets when considering the inclusion of the HNDFUE into these calculations. If we use a similar capacity number to the HND, the carbon delay cost could double. Conversely, the HNDFUE includes more Scottish projects with a different option fee structure. These figures form the Net Present Value for the delay calculations.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem impact assessment guidance.

Our expanded options will help developers choose the most appropriate option for the delivery of the coordinated assets. The AI policy extension can reduce the complexity of negotiations between developers and provide additional options for delivery, which can help reduce delays.

Competitive tendering has benefits in a range of areas. Increasing innovation and introducing new products, services and technologies are possible benefits of competitive tendering but these benefits are dynamic and hard to measure. The very late competition generator build model has the benefit of insulating the OFTO from construction risks which can help to attract a low cost of capital for the operational phase, as observed from current OFTO projects.

On the other hand, the utilisation of a late competition OFTO build can put downward pressure on transmission pricing. This is because this model allows for alternative and extended financing routes for the construction and ownership phases of development. OFTOs would also be enabled to take a whole life approach to transmission investment which could deliver an overall lower cost of capital.

Avoiding delays can help us achieve offshore wind targets earlier. Delivering offshore wind targets on time could increase GB energy security by reducing our exposure to volatile fossil fuel markets, can reduce our wholesale market prices due to a higher proportion of low marginal cost generation, and can aid decarbonisation by increasing the volume of low-carbon generation on the system. Avoiding delays can also help achieve legally binding targets in a more timely fashion.

Section 5 sets out the assumptions used in our assessments for this impact assessment.

Will the policy be reviewed?	The scope of this policy is limited to a specific set of projects and so there would be limited value in reviewing for PT2030. As the OTNR's Future Framework, formerly called Enduring Regime, is being developed, we will look to apply any lessons learned from the development and implementation of the PT2030 workstream.

Is this proposal in scope of the Public Sector Equality Duty?	Yes, we expect consumers to benefit in general, regardless of any protected characteristics.

Contents

1. Introduction

Section summary

This section outlines how the PT2030 workstream areas. It also outlines the scope of this additional draft impact assessment.

Division of the Pathway to 2030 workstream

1.1. The PT2030 workstream is one of four workstreams within the OTNR. In the PT2030 workstream, we set out the proposed approach for a holistic onshore and offshore network design. Our minded-to decision on delivery models will apply to the projects in scope of the HND and HNDFUE.

1.2. A summary of the activities in this workstream was provided in our July 2021 consultation.[10]

Table 1: Pathway to 2030 workstream areas and the scope of this impact assessment

Workstream area	Comment
Generation map	Generation map has been developed and delivered.[11]
Holistic network design (HND) and the HND Follow-up Exercise (HNDFUE)	The HND was and the HNDFUE will be produced by the Electricity System Operator (**NGESO**) in accordance with the Terms of Reference (**ToRs**) and any other relevant legislative or regulatory obligations.[12]
Detailed network design (DND) onshore	The DND for onshore transmission assets will be produced by the TOs in accordance with the ToRs and any other relevant legislative or regulatory obligations.[13] The DND onshore specifies the onshore Transmission Assets to be delivered.
Detailed network design (DND) offshore	The DND for offshore Transmission Assets will be produced by the generators in accordance with the ToRs and any other relevant legislative or regulatory obligations. The DND

[10] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[11] Offshore Transmission Network Review generation map
[12] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem, page 47
[13] Ibid. page 48

	offshore specifies the offshore Transmission Assets to be delivered.
Delivery models	**In this additional draft impact assessment, we consider three options for the delivery of relevant offshore Transmission Assets.**

1.3. The addition of the additional delivery model will be the focus of this additional draft impact assessment. It also considers the extension of the Early Opportunities AI policy[14] to projects in the scope of this workstream. The AI decision in the Early Opportunities workstream allows generators to recover capital expenditure, that is economically and efficiently spent behalf of a later user, subject to the early-stage assessment and cost assessment process. The gateway assessment process, mentioned in the PT2030 consultation, will now be integrated in the early-stage assessment development. From this point on, the process will be referred to as the early-stage assessment.

1.4. We have developed this draft impact assessment in accordance with our impact assessment guidance.[15]

1.5. Whilst we have a minded-to decision for the PT2030, this does not set precedent for the delivery model(s) that can be adopted under the OTNR's Future Framework workstream, formerly called the Enduring Regime. Key policy decisions underpinning any Future Framework would be recommended by the Department for Business, Energy and Industrial Strategy (**BEIS**) with Ofgem playing a key role in delivery, alongside OTNR partner organisations, in line with their remits. We expect a government response document to last year's Future Framework consultation to be published in due course.[16]

[14] Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
[15] Impact Assessment Guidance | Ofgem
[16] Offshore Transmission Network Review: Enduring Regime and Multi-Purpose Interconnectors (publishing.service.gov.uk)

2. Problem under consideration

Section summary

This section sets out the existing arrangements for developing offshore wind transmission assets, our rationale for intervention and the various policy objectives driving our decision-making process.

Existing arrangements

2.1. Ofgem is responsible for managing the competitive tender process through which offshore transmission licences are granted. In the developer led option, Ofgem determines the transfer value of the assets to be transferred to the OFTO[17], grants the offshore transmission licence to the OFTO and regulates the OFTO's compliance with its obligations under the licence. In the OFTO build option, Ofgem determines the OFTO at an earlier stage as the OFTO would also be responsible for the construction of the assets.

2.2. To date, all competitively tendered offshore transmission assets have been designed and built by the wind farm developers. Connecting offshore applications need to progress through the NGESO-led Connection and Infrastructure Options Note (**CION**) process, which includes collaboration with the relevant Transmission Owner (**TO**). With developer input, the CION process determines the most economical and efficient onshore connection point. A revised connection offer is issued following the CION process, which may have a different connection point or date. Connections essentially develop in isolation from one another.

2.3. The CION approach will be adapted for PT2030 projects. The connection design and post-CION offers will be based on the outputs of the HND. This will be provided for in the updated connection contracts.

[17] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 | Ofgem

Rationale for intervention

2.4. The current regime for developing and connecting offshore wind generation incentivises developers to connect individually, with competition used to reduce costs rather than promote coordination. It is now uncertain whether the existing regime can deliver the current levels of ambition in the timescales required, in a way that is efficient for consumers and appropriate for coastal communities and the environment.

2.5. Under the current delivery model, developers have had the opportunity to coordinate the development of their assets with each other. One of the reasons why this has not happened to date is that generators effectively underwrite the risk of any delay to their connection. They are therefore incentivised to complete assets as quickly as possible so that there is no risk of stranded wind farm assets. This drives generators to find the fastest route to asset delivery, which does not naturally lead to seeking collaboration with others.

2.6. To date, developers have not been incentivised to undertake AI on behalf of future projects as there was no clear route to recover the AI as part of the final transfer value of the asset transfer to the OFTO. The potential later user whose project would benefit from the AI will not commit to making a financial contribution ahead of a final investment decision. This has been a significant barrier to the development of coordinated offshore infrastructure. Without a clear AI route, projects in a coordinated design setting could be driven into extended negations with their competitors, to agree on the division of costs and labour.

2.7. This workstream was tasked with deciding on the delivery model which is best suited to deliver the HND and the more coordinated transmission infrastructure. The introduction of any form of coordination must ensure balance is maintained between the pace of delivery required to meet the government's ambition of 50GW by 2030 and introducing changes as soon as practically possible to maximise social, economic and environmental benefits.

Policy objectives

Ofgem's duties

2.8. Ofgem's principal objective is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems.[18] The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases in the security of the supply of gas and electricity to them.

Policy assessment criteria

2.9. Through the OTNR governance structures, project partners[19] have agreed a consistent set of policy assessment criteria that can be used across OTNR workstreams (Appendix 1). These serve as a tool for the OTNR project partners to aid the evaluation of policy choices at a high level and are intended to aid decision-making, as opposed to conducting detailed economic or engineering decisions at specific sites.

2.10. In assessing the options, we consider that competition should be retained where it is practicable and in the interests of consumers to do so. Our statutory duty is to carry out functions under the Electricity Act, wherever appropriate by promoting effective competition.[20] Promoting effective competition can help to achieve our principal objective of protecting the interests of existing and future consumers. It can drive efficiency and innovation, resulting in cost savings that lower consumer bills and help to meet the government's decarbonisation targets at the lowest possible cost. The importance of competition is also reflected in the OTNR policy assessment criteria (Appendix 1).

2.11. Since the start of the OTNR process, Ofgem and BEIS have engaged stakeholders extensively. This includes multiple rounds of developer bilateral meetings, industry roundtable events and an OTNR industry expert group. This engagement has enabled us to explore key barriers to coordination in more detail with industry and take a wide

[18] Our powers and duties | Ofgem

[19] Offshore transmission network review - GOV.UK (www.gov.uk)

[20] Electricity Act 1989, (s.3A(1B))

range of views into account. Barriers and opportunities raised by industry have been considered with key OTNR project partners such as NGESO, BEIS, TCE, and CES.

Stakeholder engagement to date

2.12. We published our consultation on changes intended to bring about greater coordination in the development of offshore energy networks in July 2021.[21] The consultation closed in September 2021 and 74 responses were received. In January 2022, we provided an update on the consultation with summary of the responses, next steps and indicative timelines.[22] In May 2022, we published our minded-to decision to apply a very late competition generator build model to non-radial offshore transmission assets in scope of the workstream. We also consulted on the consequential arrangements that may be required to implement the delivery model. We received 29 responses. We also received feedback during the HND launch webinar and multiple bilateral meetings since the May 2022 publication.

2.13. In April 2022, we consulted on our Early Opportunities minded-to decision on AI and the implementation of policy changes to facilitate AI capital expenditure (**capex**) recovery for projects pursuing coordination. We received 18 responses. Feedback received demonstrated a broad agreement with our proposals regarding consumers sharing the risk associated with AI, the introduction of an early-stage assessment process and, to a lesser extent, the extension of user commitment arrangements to the potential later user(s).

[21] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[22] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

3. Approach

Section summary

This section describes our approach to the impact assessment. This section also outlines our determination of "importance" within the meaning of Section 5A of the Utilities Act 2000 with regards to this additional draft impact assessment.

Options analysis steps and proportional approach

3.1. We outline below the steps we have taken to assess the expanded package of options against the original proposal:

a) We considered the responses received for the May 2022 publication. We mapped out common themes in the responses towards our minded-to decision. The majority of the responses wanted the expansion of options available for developers when delivering coordinated assets.

b) We considered what further options could be made available to developers for non-radial transmission assets under PT2030 and whether to apply these.

c) We revisited our calculation assumptions after the HND and the asset classification decisions were published. The number of non-radial transmission assets was smaller than we had previously assumed. Three out of the 21 assets were classified as non-radial offshore transmission assets.

d) We reassessed what the delay costs in terms of carbon and option fees could be with only three non-radial offshore transmission assets.

e) We assessed the risks and opportunities for expanding the Early Opportunities AI policy for the projects in scope of the PT2030 workstream. We concentrated on the fact that the assets were less speculative, larger and impacted on the wider network benefit.

f) We reassessed the addition of late competition OFTO build model as an option. We used the revised delay calculations and assumptions in our analysis.

Monitoring and evaluation

3.2. Lessons learned from the development and implementation of the PT2030 workstream will be applied to the development of the Future Framework for the delivery of offshore transmission assets.

Determination of "importance" within the meaning of Section 5A of the Utilities Act 2000

3.3. Under Section 5A of the Utilities Act 2000 **(UA2000)**, we are required to carry out an impact assessment when:

- we are proposing to do anything in connection with our functions as set out in the Gas Act 1986 or the Electricity Act 1989; and
- it appears that such proposal is important.[23]

3.4. Section 5A(2) of the UA2000 specifies the situations where a proposal is to be considered "important" for the purposes of determining whether an impact assessment should be carried out. This includes if the implementation of the proposal would have "a significant impact on:

- persons engaged in commercial activities connected with … the generation, transmission, distribution or supply of electricity[24]
- the general public in Great Britain or in a part of Great Britain".[25]

3.5. Our delivery model minded-to decision for the workstream has a significant impact on persons engaged in the generation and transmission of electricity, or in connected commercial activities. It will also have a significant impact on the general public in Great Britain or part of Great Britain. Thus, we have determined it to be "important" in terms of Section 5A of the UA2000.

[23] Utilities Act 2000 s5A(1)
[24] Utilities Act 2000 s5A(2)(c)
[25] Utilities Act 2000 s5A(2)(d)

4. Options

Section summary

This section considers the expanded package of options for the delivery of coordinated assets within the scope of the of PT2030, and sets out our counterfactual scenario.

Counterfactual and factual scenarios

4.1. We considered counterfactual and factual scenarios for delivery of the non-radial offshore transmission assets:

- Counterfactual: we proceed with only the very late competition generator build delivery model for non-radial transmission assets within the scope of this workstream.

- Factual: we give developers expanded options for non-radial transmission assets within the scope of this workstream:
    - working collaboratively with other developers using a very late competition generator build model (our original minded-to position); **or**
    - using the very late competition generator build model, now incorporating the option of extended AI policy, thus avoiding a requirement to for developers to enter into commercial arrangements in respect of shared infrastructure; **or**
    - using a late competition OFTO build model.

Delivery of assets in counterfactual scenario

4.2. In the counterfactual scenario, we proceed with the very late competition generator build delivery model for non-radial transmission assets within the scope of this workstream, without the extension of the AI policy. Developers would agree together on how the building and financing of coordinated, HND indicated, assets would happen. After construction, the assets would be tendered out in a very late competition, similarly to the radial model.

4.3. The offshore generators would undertake the DND, consenting and construction of the coordinated assets, as included in the HND. A competitive tender process would be

carried out to transfer ownership of operational assets to an OFTO. This process would require the generators to develop the assets together or to commercially agree that one of them would develop the assets on behalf of the other one.

Delivery of assets in the factual, expanded options, scenario

Expansion of the Early Opportunities AI policy to the PT2030 workstream

4.4. The Early Opportunities workstream's decision covered policy changes to clarify AI capital expenditure recovery processes for projects pursuing coordination within the scope of the Early Opportunities workstream.[26] The policy expansion to PT2030 workstream will help reduce the risk associated with AI for developers and reduce the barriers to coordination, for projects within the scope of this workstream.

4.5. The changes included:

- Allocation of AI risk between the consumer and later user(s) of shared transmission infrastructure developed under the Early Opportunities workstream.
- Introducing the early-stage assessment for developers.
- Extension of user commitment arrangements to the potential later user of AI funded offshore transmission infrastructure.

4.6. The consumers will bear AI risk in advance of the later user(s) connecting to coordinated assets. The costs which accrue until that point of connection will be for the account of the later user when they connect. If the later user fails to connect, charges which would have otherwise been paid in respect of the AI element will remain with consumers.

4.7. The HND has shown that in some cases, coordinated assets could be delivered by a single developer carrying out AI works on behalf of a later user. The initial developer could carry out these works without the need to conclude formal commercial arrangements with later user(s). In this case, extension of AI principles to PT2030 would mean that delivery of coordinated connections could go ahead quickly even where projects are on different timescales which would otherwise prove challenging

[26] Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem

to coordinated development. This encourages developers to build coordinated assets because it provides a route to recovery of economic and efficient costs of the AI.

Retaining the very late competition generator build option

4.8. We will retain the very late competition generator build option for the projects in scope of the workstream (see 4.1 above).[27] Developers will have the freedom to choose to collaborate with each other on non-radial offshore transmission assets where it makes sense for them to do so.

Addition of the late competition OFTO build for non-radial transmission assets

4.9. The late competition OFTO build option would require generator(s) to undertake the detailed design and consent of the coordinated assets, with the subsequent appointment of an OFTO to construct and operate it following a competitive tender process. A similar option exists in the radial OFTO regime, although it has to date not been selected by developers.

4.10. Ofgem has in the past considered various late competition OFTO build tender frameworks which enable the OFTOs and generators to have varying degrees of control over procurement and construction management.[28] Stakeholder engagement and decisions regarding the make-up of late competition OFTO build model is expected to start in the first part of 2023.

4.11. Providing a late-competition OFTO allows developers to select the most appropriate delivery model for the non-radial offshore transmission infrastructure for their projects if they collectively deem it to be optimum method of delivery. This option could ease coordination pressures in the post-consenting phases of development. It would give developers another option if they are not able to advance coordinated assets by way of agreed collaboration. OFTO build also provides another route to delivery if a developer does not wish to fund the capex for AI, until asset transfer, under the generator build model. This could be the case, if the developers prefer not to use AI, in cases where the cost of the necessary AI is deemed too high to be risked by a single developer.

[27] Minded-to Decision and further consultation on Pathway to 2030 | Ofgem
[28] OFTO Build: Providing additional flexibility through an extended framework | Ofgem

4.12. We recognise that the late competition OFTO build option still includes a level of coordination between developers. As the number of users of GB waters increases, we see some level of coordination between stakeholders to be the new normal. We do not see working in complete isolation to be a viable route forward when it comes to developing offshore assets.

4.13. We recognise that we will need to develop the process for the late competition OFTO build model including, the details of the tender process, and associated tender guidance and cost assessment documents.

4.14. We had previously identified that the development of this regime for non-radial offshore transmission assets could lead to delays for projects within the scope of this workstream. Due to the number of non-radial transmission assets identified in the HND being lower than we had initially assumed, the impact of potential delay associated with the development of this model is reduced. This means that the costs of any delay from the development of this model (in terms of the financial cost of option fees and the carbon cost) are lower than we had initially modelled (see section 5.8).

5. Assumptions, Uncertainties and Risks

Section summary

This section considers the cost assumptions and estimated delivery timescales we used in our options analysis.

Our assumptions

Set up costs

5.1. Setting up of the late competition OFTO build tender regime and cost assessment processes will require additional resources to be allocated within Ofgem.

Potential cost savings with late competition OFTO build

5.2. A late competition OFTO build could put downward pressure on transmission pricing because of increased scope of competition. We estimated costs to decrease by 5-10% with late competition, when compared with the very late competition model.

5.3. We recognise the risk that the capex cost saving estimates for the different competition scenarios could vary between projects. We consider that providing a five percent range for the late competition OFTO build scenario should cover the potential range.

Timescale for delivery of offshore transmission assets

5.4. We assumed that the assets would be constructed at the same speed irrespective of the entity which would deliver them. We estimated the construction window for the coordinated assets to be between 3-5 years. We reached this assumption based on the facts that all parties are likely to be procuring goods and services from a similar pool of suppliers – and therefore construction was likely to take the same length of time whether it was undertaken by OFTOs or generators.

5.5. We believe that our original assumption of a six-month period for developers to complete commercial negotiations for the delivery of coordinated assets was too optimistic. We now estimate that there could be a delay of up to one to two years in

the delivery of non-radial offshore transmission assets if developers only have the very late competition generator build model available to them. The extension of options available to developers may help shorten negotiation times and break potential deadlocks between developers, or provide routes forward where project circumstances mean the very late generator build model is challenging.

Reduced number of non-radial transmission assets

5.6. Our previous delay cost analysis was based on ~19GW being delivered through the HND. This includes the LR4 ~8GW and first ~11GW of ScotWind. The ScotWind figure was reached based on initial discussions with NGESO about ScotWind inclusion in the HND and delivery queues.[29]

5.7. The HND ended up facilitating the connection of 21.8GW of wind.[30] This included LR4, the first tranche of ScotWind and one previous project. There was an additional 1GW of capacity which was subject to Celtic Sea leasing round outcomes.

5.8. The non-radial transmission assets' capacity totals 5,400MW, around 15% of the HND's total 35,890MW of transmission assets. In our monetised impact calculations, we are using the 5,400MW figure to reflect the smaller number of non-radial transmission assets, compared to the ~19GW used in the first draft impact assessment. We recognise that calculating delay figures with the 5,400MW figure, presumes the delay of all three projects.

5.9. We consider this to be a proportionate method for estimating delay costs as we do not have definite insight into the proportion of non-radial transmission assets included in the HNDFUE. If the HNDFUE includes a similar number of non-radial transmission assets as the HND (5,400MW), the carbon delay costs could be derived from twice the amount of non-radial transmission assets 10,800MW.

[29] Further information about ScotWind inclusion in the HND and NGESO thinking can be found on the related NGESO press release on 11 February 2022. Inclusion of ScotWind in the Holistic Network Design - National Grid ESO

[30] The Pathway to 2030 Holistic Network Design | National Grid ESO

Risk of extending the AI policy

5.10. There may be circumstances in which non-radial offshore transmission infrastructure could be constructed by an initial user with the use of AI (as opposed to by the first and later users in a formal collaboration). If this facilitates the delivery of the non-radial offshore transmission assets under the HND or HNDFUE, there are benefits to consumers to underwrite the costs associated with the AI, until the later user connects. or if the later user fails to connect at all. These risks and how they are mitigated with regards to the AI policy extension to the PT2030 projects, is further covered in the accompanying consultation document.

6. Monetised costs and benefits

Section summary

This section considers the cost of potential delay of not expanding the options available to developers when developing coordinated assets included in the HND. The delay costs are calculated in terms of both option fees and carbon.

Cost of delay calculation differences between the draft impact assessments

6.1. In the first draft impact assessment, we estimated the cost increases or decreases that no competition, early competition and late competition could bring, compared with the current very late competition model.

6.2. In this additional draft impact assessment, we also focus on the delay costs. This impact assessments delay costs are derived caused developers being drawn into extended negotiations to reach coordination agreements. We estimate that our expanded options, in terms of delivery models and the AI policy extension, could help avoid a one-to-two-year delay caused by these lengthy negotiations. For our estimates, we use the reduced number of non-radial transmission assets and their potential delay costs in terms of carbon and option fees.

More delay causing resulting in more annual option fee payments

6.3. When we look at the costs associated with delays, it is important to consider costs associated with option fees. The longer developers take to reach coordination agreements with each other, the longer English and Welsh developers pay annual option fees.

6.4. We would expect that some, if not all, of the option fee costs would be passed on to the consumers through developers' higher Contracts for Difference (**CfD**) bids. This in turn would raise consumers' bills. Although we cannot be certain about developers' commercial strategies, and that all of these increased costs would be passed through to consumers, it is reasonable to assume some level of cost pass-through will occur. Therefore, a reduction in option fee costs would be classified as a potential benefit for

energy consumers. However, from a societal perspective, option fees are a transfer from developers (and potentially ultimately consumers) to TCE and HM Treasury.

6.5. Projects in both ScotWind and LR4 pay option fees to Crown Estate Scotland and The Crown Estate respectively. ScotWind projects pay a single fee when they enter an option to lease – this secures the option for ten years. In contrast, LR4 projects pay an annual fee from the time they enter an option to lease until they the companies get the final planning permission.

6.6. In the HND, the proportion of LR4 projects was higher than ScotWind projects. This means that the impact of delay is higher in terms of the option fees payable because LR4 projects have annual option fees. In the HNDFUE, the proportion of ScotWind projects is higher than LR4 projects.

Cost of delay in carbon

6.7. Our expanded delivery options, in terms of delivery models and the AI policy extension, can help avoid a potential one-to-two-year delay caused by developers being drawn into lengthy coordination negotiations. These negotiation delays could delay renewable offshore wind from being connected to grid.

6.8. These delays would in turn delay the offshore wind needed to decrease the amount of thermal generation connected to the grid. In valuing emissions for appraisal purposes, the government places a value on carbon, based on estimates of the abatement costs that will need to be incurred to meet specific emissions reduction targets.[31] This is calculated by assuming that each MWh of new offshore generation would displace generation at the average grid carbon intensity, based on BEIS emissions factors and projected carbon pricing values.[32] We use the grid average because we are considering a significant amount of wind power, which would likely displace more than just the marginal generator (which usually has higher emissions), and so our approach avoids

[31] Valuation of greenhouse gas emissions: for policy appraisal and evaluation - GOV.UK (www.gov.uk)
[32] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal

overestimation of benefits. The estimates use a low and high load factor estimates.[33] These are discounted, marginal abatement values which used central carbon values.

[33] The low load factor based estimates were reached using a web tool (Wind, v1.1, Europe, 1980-2016 dataset) developed by Iain Staffell and Stefan Pfenninger from Imperial College London and ETH Zürich (Staffell and Pfenninger, 2016).Staffell and Pfenninger, 2016).Staffell and Pfenninger, 2016). The tool estimates the average load factor for future wind turbine models on a GB offshore average based on 1980-2016 wind data. The high load factor estimates used BEIS provided load factors (fixed and floating, mixed technologies used median of the two load factors) for LR4 CfD allocation framework (Annex 3).

7. Non-monetised costs and benefits

Section summary

This section focuses on the importance of competition and the effects of the minded-to decision on energy security and wholesale energy prices.

The use of competitive tendering in delivery

7.1. Competitive tendering has benefits in a range of areas. While it is difficult to quantify all the impacts of opening markets up to competition, increasing innovation and introducing new products, services and technologies are possible.[34]

7.2. We have a duty to carry out our functions in the best way calculated, to further our principal objectives and wherever possible, promote effective competition where it can deliver benefits to consumers (whether that be in terms of cost or time savings or wider benefits). The benefits could also be in terms of introducing innovation or cost discovery.

Increasing energy security by reducing risk of delay

7.3. We are seeking to reduce the risk of delay and non-delivery of non-radial offshore transmission assets. Expanding the options available to developers can help do this. Delivery of the PT2030 network assets is essential in meeting the government's ambition of 50GW of offshore wind by 2030. This will help reduce GB reliance on fossil fuels and reduce exposure to the volatility of international fossil fuel prices which are beyond our control.[35] This also has the potential to reduce our wholesale market costs, as offshore wind has a low marginal cost when compared to typical thermal generators.

[34] Early Competition Plan Cost Benefit Analysis Consultation November 2022 Please see appendix 2 for examples. We recognise that some the examples do not directly refer to offshore competition.
[35] Major acceleration of homegrown power in Britain's plan for greater energy independence - GOV.UK (www.gov.uk)

8. Options analysis

Section summary

The section considers the counterfactual scenario of proceeding only with very late competition generator build model for non-radial transmission assets, without the expansion of policy options. It also considers the expanded options. The first option being the application of AI policy to the PT2030 workstream. The second option being the inclusion of the late competition OFTO build model for the delivery of non-radial offshore transmission assets in scope of PT2030.

Counterfactual

8.1. In the counterfactual scenario, we proceed with the very late competition generator build delivery model for non-radial transmission assets within the scope of this workstream, without the extension of the AI policy or the availability of the late competition OFTO build model. Developers would together agree on the design, development and construction of coordinated assets as recommended in the HND. After construction, the assets would be tendered out in a very late competition, in the same way as radial offshore transmission assets.

8.2. In the first draft impact assessment, we estimated that this scenario would not lead to any significant delays. We previously estimated that it would take developers six months to reach coordination agreements with each other.

8.3. In response to the May 2022 publication, developers stated that they foresaw challenges with this option. In particular, they indicated that the assumption we made as to the length of time it would take for commercial negotiations to conclude to allow coordinated development of non-radial offshore transmission assets.

8.4. They indicated that it would potentially be very challenging to coordinate without the extension of the AI policy and the right delivery model optionality. Without the expanded package of options, developers could be drawn into lengthy formal cooperation negotiations causing the projects to be delayed beyond the 2030 target. These factors combined could potentially result in cases of non-delivery of the non-radial transmission assets.

8.5. Taking on board this feedback, we estimate a one-year delay without the expansion to be likely and two years of delay to be somewhat likely.

8.6. After the publication of the HND and the application of the asset classification process, the non-radial transmission assets account for 5.4GW of capacity, instead of the original 19GW. The first year of delay in terms of discounted carbon costs is now estimated at £147m-237m and two years is estimated at a cumulative £267-429m. We estimated that the first year of delay, in terms of discounted option fees, would result in ~£351m costs, being paid by developers in aggregate to the Crown Estates and Treasury. For two years of delay the figure would cumulatively increase to £679m.

Table 2: Discounted delay cost estimates (in millions, GBP) for the May 2022 publication, the updated HND and HNDFUE figures.

Discounted delay cost estimates (in millions, GBP)	Likely delay to 2031 if options not expanded	Somewhat likely delay to 2032, if options not expanded
May 2022 - cumulative option fees delay (all LR4 included)	£645	£1,268
May 2022 - low carbon scenario (19G)	£521	£963
May 2022 - high carbon scenario (19GW)	£819	£1,513
Cumulative option fees delay (partial LR4 included)	£351	£679
Low carbon scenario (5.4GW)	£147	£267
High carbon scenario (5.4GW)	£237	£429
Option fees + Low carbon (5.4GW)	£499	£946
Option fees + High carbon (5.4GW)	£588	£1,108
HND + HNDFUE low carbon (10.8GW)	£295	£535
HND + HNDFUE high carbon (10.8GW)	£473	£859
HND + HNDFUE low carbon (10.8GW) + option fees (partial LR4)	£646	£1,213
HND + HNDFUE high carbon (10.8GW) + option fees (partial LR4)	£825	£1,537

Retention of very late competition generator build as one of the options

8.7. We anticipate that some projects will find formal commercial agreements, including joint ventures, as the most suitable option when developing non-radial transmission assets. Throughout the OTNR process, developers have in general expressed their preference towards retaining control over their projects and limiting interfaces between delivering parties. The developers have also highlighted their track record of delivering radial assets in the GB market.

Extension of the AI policy

8.8. As part of the Early Opportunities workstream we have issued a decision to allow for recovery of AI by developers. We have also decided on the allocation of how the costs and risks associated with the AI should be allocated between consumers and the users of the AI. The recovery of AI will be subject to an early-stage assessment to determine if it meets the objectives of the OTNR. Recovery of the AI costs via the final transfer value at the asset transfer to the OFTO will be subject to a cost assessment process.

8.9. The Early Opportunities analysis indicated that allowing developers to utilise AI in the development of coordinated infrastructure with consumers underwriting that risk until the later user connects, was likely to result in the greatest consumer net benefit.[36]

8.10. This analysis was supported by a report commissioned from the technical advisory firm DNV. The report considered the estimated capex values for the offshore transmission infrastructure required for the connection of two generic offshore wind generators based on either separate connection assets or shared connection assets.[37] In the coordinated scenario, the initial user develops and installs assets that would also be used by the potential later user. Two generator designs are considered in the report: Design 1 and Design 2, which are summarised in Table 3.

Table 3: Generic offshore wind farm design specifications

Policy option	Project 1 capacity (MW)	Project 2 capacity (MW)	Project 1 cable length from OFTO offshore substation to landfall (km)	Project 1 cable length from landfall to OFTO onshore substation (km)	Project 2 cable length from OFTO offshore substation to landfall (km)	Project 2 cable length from landfall to OFTO onshore substation (km)
Design 1	500	400	50	20	60	20
Design 2	800	800	55	20	65	20

[36] Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
[37] Offshore Coordination - Early Opportunities: Consultation on our Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
The DNV report is available in the draft impact assessment's Appendix 2.

8.11. The report's analysis showed that for both designs, the coordinated scenario leads to significant savings in the total capex of the transmission system(s). The report's Design 1 achieves a 30% saving from 417 to 293 million pounds, and Design 2 achieves an 18% savings from 564 to 468 million pounds (see table 4).

Table 4: Estimated total capital costs of offshore transmission assets for two generators in counterfactual and coordinated scenarios

	Counterfactual (£m)	Coordinated (£m)	Savings (%)
Design 1			
Total offshore transmission capex	417.4	293.3	30%
Design 2			
Total offshore transmission capex	564.2	467.9	17%

8.12. The report suggested that in the final impact assessment, the chosen policy option would result in an indicative net benefit to consumers of £14.6 million if the later user connects and uses the shared assets. This figure excludes potential additional benefits that may flow from generators to consumers through any reduction in CfD allocation round clearing price due to other capital cost savings.

8.13. If the potential later user fails to connect and use the assets, with no recovery of user commitment amounts from the potential later user, the modelled net cost to consumers in this example is £138 million. The workstream proposed to implement the early-stage assessment process to manage this risk to consumers and proposing the extension of user commitment arrangements to mitigate the cost to consumers if the later user fails to connect.

8.14. We expect the risk of the later user failing to connect is lower for the projects in scope of the PT2030 workstream compared to the projects in the Early Opportunities workstream because the centralised design aspects of the HND. As the HND indicates the most suitable assets for the offshore and onshore connections, this helps to avoid unnecessary AI spend.

8.15. We recognise that the coordinated assets involved in the HND and HNDFUE will potentially require larger amounts of investment than the voluntary coordination-based assets in the Early Opportunities workstream. The larger assets are a key component in delivering the HND design which is estimated to lead to overall net

consumer savings of approximately £5.5bn (capacity and constraint costs).[38] The AI policy is an effective mechanism to help deliver the coordinated assets which forms part of the HND, including wider network benefit infrastructure used by the TOs for onshore transmission purposes.

8.16. The extension of the AI policy can help developers deliver coordinated offshore transmission assets without the need to conclude formal commercial arrangements with later users. Forming these commercial arrangements could be particularly challenging where projects are on different timescales. Allowing for the use of AI in place of formal collaboration arrangements may help save valuable delivery time and help deliver the assets within the scope of the HND in line with the government's 2030 ambition.

Addition of the late competition OFTO build delivery model option

8.17. Late competition OFTO build has multiple potential benefits. However, in our May 2022 publication analysis, we did not deem these benefits to be sufficient for us to adopt this option. These benefits were weighed against the potential delay costs calculated for the 19GW of potential non-radial assets (see Table 2). We now propose to include this model as part of the expanded package of options to increase developers' delivery options, to address possible issues around non-delivery or delays, and because the cost of delay is less than we initially expected.

8.18. There may be circumstances in which developers do not see the very late generator build model as the optimum solution for the delivery of non-radial offshore transmission – for example, where there is a sensitivity on the sharing of confidential or proprietary information with a competitor or where they fail to reach a commercial agreement (or where reaching such agreement would take longer than alternative options).

8.19. Even with the introduction of AI as an additional option to facilitate the delivery of shared infrastructure, a generator build option may not be feasible. This could be the case if there is no natural lead developer among the affected projects or where no developer is willing to fund the make AI on behalf of another project. In these

[38] The recommended design leads to an additional £7.6 billion of capital costs due to the additional offshore infrastructure. However, this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. NGESO Cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021 prices.

circumstances, the development of a late competition OFTO build option for coordinated assets will provide a further option for developers to ensure that there is a route for delivery of the coordinated projects and that developers have the flexibility to opt for a model that best reflects project circumstances.

8.20. There is a possibility that the development of the late competition OFTO build option could result in some delays. However, we consider this option to effectively mitigate against the risk of non-delivery by providing more optionality and flexibility to suit project-specific circumstances.

8.21. A late competition OFTO build model could provide financial benefits which help balance costs caused by the non-radial transmission assets being delayed. These benefits are speculative as we have not run a late competition OFTO build before. Although, as noted previously, costs and benefits are reduced due to the smaller number of non-radial transmission assets having been determined through the asset classification process. An OFTO build model can put downward pressure on transmission pricing because the late competition may allow alternative and extended financing routes. This can offer more choice for funding solutions as well as different funding providers for transmission asset construction. This is underpinned by an existing offshore transmission regime including an A-rated counterparty in NGESO, an established OFTO equity and debt funding market and strong public sector institutional support.

8.22. OFTOs would be enabled to take a whole life approach to transmission investment to deliver an overall cost of capital which is potentially competitive relative to generator build. The model can provide early clarity and certainty for generators on future capital expenditure and network charges. The model would allow generators to focus on their core business, in accordance with the generator's capability, capacity and risk appetite for involvement in offshore transmission. The model can also introduce additional transmission specialists into the GB market.

9. Appendices

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Appendix 1: Policy Assessment Criteria

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 Revolution10 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 but will be steered by its statutory duties to make decisions that are in the best interests of consumers.

- 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 onshore competition 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, sand wave 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. • AI 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 2: Glossary

A

Anticipatory investment (AI)
Investment that goes beyond the needs of immediate generation, reflecting the needs created by a likely future project, projects or the wider transmission system.

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

BESS
British Energy Security Strategy

C
CAPEX
Capital expenditure

CES
Crown Estate Scotland

CfD
Contracts for Difference

CION
With developer input, the CION process determines the most economical and efficient onshore connection point.

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
The Electricity Act 1989 as amended from time to time.

Early-stage assessment
Early-stage assessment being developed for both Early Opportunities and PT2030 workstream projects. The early-stage assessment assesses the projects' anticipatory investment proposals.

NGESO
National Grid Electricity System Operator

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.

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 PT030 workstream.

HNDFUE
Holistic Network design follow-up exercise. It is the follow up to the HND.

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.

OTNR
The Offshore Transmission Network Review (OTNR) was launched to ensure that future connections for offshore wind are delivered with increased coordination while ensuring an appropriate balance between environmental, social and economic costs.

P

PT2030
The Pathway to 2030 forms part of the Offshore Transmission Network Review. It aims to develop the regulatory framework to allow the optimum engineering solution to connect 50GW of offshore wind to the system by 2030.

L

LR4

Leasing round 4 is the Crown Estate led offshore seabed leasing round which offers the opportunity for at least 7 GW of new offshore wind projects to be developed in the waters around England and Wales.

S

ScotWind

ScotWind is a Crown Estate Scotland led offshore seabed leasing round. ScotWind is the first Scottish offshore wind leasing round in over a decade and the first ever since the management of offshore wind rights were devolved to Scotland. 20 projects have been offered option agreements which reserve the rights to specific areas of seabed.

T

TCE

The Crown Estate

Tender Regulations

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

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 PT2030 workstream of the Offshore Transmission Network Review.

Transmission Assets

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.

TNUoS

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