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Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks

Launched in July 2020, the Offshore Transmission Network Review (OTNR) seeks to deliver increased coordination of offshore transmission and interconnection. The aim is to find a better balance between environmental, social and economic costs in support of the UK's targets of 40GW of offshore wind by 2030 and net zero by 2050. 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 offshore wind developers operate.

The Electricity System Operator's (ESO) Offshore Coordination Phase 1 report published in December 2020[1] demonstrated 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. Multiple-purpose interconnectors (MPIs) also play a role in delivering these benefits.

Given the scale of ambition for offshore wind, the existing model will not be appropriate to deliver on the objectives of the OTNR. It was for this reason that we published our

[1] Phase One Final Report (nationalgrideso.com)

consultation on changes intended to bring about greater coordination in the development of offshore energy networks[2] in July 2021. This was the first in a series of consultations that will be published as part of the OTNR and covered three components of the review:

- Early Opportunities – setting out proposals to enable developers to make changes to coordinate in-flight projects;
- Pathway to 2030 – setting out the proposed approach for holistic onshore and offshore network design to enable coordination in the delivery of the 40GW by 2030 target, and identifying high-level options for delivery models for any required coordination of offshore transmission infrastructure; and
- Multi-Purpose Interconnectors (MPIs) - exploring the feasibility of using the existing legal frameworks to facilitate early opportunity MPI projects.

The consultation closed in September 2021 and 74 responses were received.
The purpose of this publication is to provide a summary of those responses. It also sets out more detail on the next steps for each workstream prior to our decisions and further consultations in Spring 2022:

- Early Opportunities – we are developing changes to facilitate anticipatory investment which would advance the aims of the OTNR, subject to a cost-benefit analysis and more detailed proposals on when such investment would be appropriate and how the risks to consumers can be minimised;
- Pathway to 2030 – we are narrowing the range of options on the models for delivery of coordinated offshore transmission assets for Scotwind and Crown Estate Leasing Round 4 projects, discounting models that would likely delay delivery against government's target of 40GW of offshore wind by 2030.
- MPIs – Taking account of feedback and analysis, we intend to publish a minded-to decision in Spring 2022 setting how we think we can adapt the existing licensing framework for MPIs on an interim basis. Assuming this is feasible, this will be followed by a decision and an implementation consultation in due course.

The timeline below provides an indicative summary of the key stages of our next steps for the relevant workstream areas.

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[2] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

If you have any questions about this publication or if you wish to discuss its contents, please contact Offshore.Coordination@ofgem.gov.uk.

Yours faithfully,

Stuart Borland
Deputy Director
Offshore Network Regulation

Annex 1 – Update on Early Opportunities Workstream

Workstream context

1.1 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.

1.2 The questions raised in our consultation in July 2021 asked for input into some of the regulatory changes which are under consideration to ensure these Early Opportunities projects are supported whether through changes to the current regime or through the removal of barriers to timely delivery.

Next steps for workstream

1.3 Development of detailed policy proposals is ongoing and we intend to issue a further publication in Spring 2022 which will set out more details on the following matters.

1.4 A decision on the manner in which the risk of anticipatory investment will be shared with consumers and how this will facilitate greater investment in coordinated offshore transmission assets in line with the objectives of the OTNR.

1.5 Details on the qualifying criteria which will apply to allow the recovery of anticipatory investment via a cost assessment process and the application of such to ensure consumer interests are protected against anticipatory investment which would be inefficient or fail to deliver on the objective of increased coordination.

1.6 Proposals on additional mechanisms to achieve a risk reward balance between developers, consumers and future beneficiaries of assets funded by anticipatory investment.

1.7 We will consult stakeholders on any further changes required to the framework that will facilitate implementation, including any changes to the Tender Regulations, cost assessment guidance and licence conditions which may be required.

1.8 We note that in parallel to our work, there has been a call for evidence of transmission network use of system ('TNUoS') reform.[3] We will be working closely with colleagues on any proposed changes to TNUoS to consider how such reform might facilitate increased offshore coordination.

1.9 For any implementation of the above referenced matters, we expect the ESO will take the lead in developing and proposing the 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 the appropriate parties to propose the necessary modifications. We will engage with industry parties (and subsequent workgroups) that bring forward relevant code modifications.

1.10 We will continue to engage with BEIS to explore policy options addressing the management of anticipatory investment risk in the Contract for Difference ('CfD') regime.

Summary of responses to questions

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

1.11 We received 34 responses to this question. Stakeholders were broadly supportive of the six proposed concepts listed in our consultation.

1.12 Fourteen stakeholders suggested that the regulatory framework should have sufficient flexibility to accommodate new or varied concepts beyond those proposed in the consultation. Some responses proposed potential combinations of the proposed concepts. A number of stakeholders flagged that coordination should be broadly defined to encompass a range of activities from cooperation in construction of infrastructure, through coordination of design and installation, to full electrical integration of the transmission infrastructure used by different projects.

1.13 Based on the feedback to this question, we believe that the concepts on which we have consulted broadly reflect the likely scope of Early Opportunities Projects. Beyond the six concepts identified, we note that there are additional activities (such as coordinated construction) which have potential to deliver the objectives of this

[3] TNUoS Reform - a Call for Evidence | Ofgem

workstream. We recognise that the regulatory framework should have sufficient flexibility to facilitate these.

1.14 Several stakeholders noted that the proposed concepts would be technically difficult to deliver within the timeframes of the Early Opportunities workstream, irrespective of the relevant commercial barriers being addressed. The identified technical challenges include the requirement for extensive code modifications, particularly relating to the treatment of HVDC systems, as well as the limited supply chain for large offshore substations.

1.15 The requirement for code modifications to facilitate projects in this workstream is discussed under question 6. The OTNR will continue to monitor additional challenges including technical and supply chain matters, which may be a barrier to the delivery of Early Opportunities projects.

1.16 Several stakeholders noted that the proposed concepts may result in additional offshore transmission infrastructure compared to the relevant counterfactual scenarios, with the risks of increased impacts on the marine environment and increased costs to consumers.

1.17 As per the stated aim of the OTNR, changes to support increased offshore coordination must ensure an appropriate balance between environmental, social and economic costs. This will be an ongoing metric against which all proposed changes will be measured.

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

1.18 In this consultation question, we use the term 'anticipatory investment' to refer to investment in offshore transmission infrastructure to support the later connection of specific offshore developments. This investment goes beyond the needs of the immediate offshore development or developments.

1.19 To date, developers have not been incentivised to undertake anticipatory investment on behalf of future projects. To do so has been commercially complex and financially unattractive, increasing project costs with no clear route to recovery of those costs. Without changes to the regulatory framework, it is unlikely that developers would be willing to drive meaningful anticipatory investment in coordinated offshore transmission assets.

1.20 We received 38 responses to this question. Of these, 32 respondents believed that there was a need to share the anticipatory investment risk between offshore wind developers and consumers as a means to support the objectives of the OTNR and increase levels of coordination in offshore transmission assets.

1.21 Three respondents disagreed with any form of sharing risk with consumers, noting that offshore wind developers are best placed to manage development risk including the risk of making anticipatory investment. This would represent a continuation of the status quo which has not resulted in the delivery of coordinated offshore transmission assets.

1.22 We do not believe that increased coordination (in situations where anticipatory investment is required) will occur without a change to the manner in which anticipatory investment is treated. There was a range of views on how the risks associated with anticipatory investment should be managed between the relevant developers and consumers.

1.23 Ten stakeholders suggested that the risk associated with an anticipatory investment should be allocated between the relevant projects and consumers by reference to the potential benefits of that investment. However, it was noted that this could result in a continuation of the status quo and a brake on coordination if developers are considered to be the sole beneficiaries of the anticipatory investment in question.

1.24 Sharing between projects only remains a particular challenge where the later project(s) is/are in an earlier stage of development. In this case, a likely future user of shared offshore transmission infrastructure cannot commit to the cost of such infrastructure prior to taking their final investment decision. This has been the case with developments to date. A final investment decision is usually made by developers after the award of a CfD which may be some time after the construction of the first project which has committed to the anticipatory investment for transmission assets. This has historically limited the extent to which a future developer would make a commitment to anticipatory investment and brings us to the status quo. The role of allocating some risk to consumers is to assist in bridging this timing challenge.

1.25 As noted above, an overwhelming majority of respondents were in favour of sharing the development risks associated with anticipatory investment with consumers, in order to achieve the objectives of the Early Opportunities workstream. These responses highlighted the potential benefits to consumers from anticipatory investment which included overall reduced capital costs, reduced environmental impacts, accelerated connection of offshore wind generators, reduced impacts on communities in the vicinity of the associated transmission infrastructure, and wider socio-economic benefits.

1.26 Taking all of the above feedback into consideration, we recognise and agree that changes need to be made to how anticipatory investment is treated so that developers are incentivised to coordinate infrastructure development. Given the challenges of sharing costs between projects at varying stages of development, we intend to develop a process in which consumers would assume some risk in advance of subsequent projects connecting to shared infrastructure. This will involve changes to the relevant cost assessment process, and may also sit alongside changes to the TNUoS methodology in respect of offshore shared infrastructure.

1.27 However, risk to consumers should be minimised and consumers should not be asked to carry risk greater than that which is strictly necessary for delivery of the objectives. We are currently undertaking more detailed cost-benefit analysis (CBA) on the allocation of anticipatory investment to consumers and a range of options which would act as mitigants to the risks consumers would assume. These include the potential provision of User Commitment by subsequent developers and further consideration of the extent to which and how any consumer payments towards anticipatory investment might be refunded by the later users of such investment.[4]

1.28 Stakeholders broadly agreed with the proposal that our general proposed treatment of anticipatory investment will be subject to detailed CBA to protect consumers' interests from the risk of anticipatory investment that is inefficient or is otherwise not demonstrably beneficial to either/both the system or consumers.

1.29 A number of stakeholders suggested that Ofgem should undertake phased assessments of any proposed anticipatory investment, with one assessment taking place at a sufficiently early stage of project development to inform subsequent development decisions relating to design, planning and procurement. Those responses suggested that each assessment should determine whether the proposed anticipatory investment will, in principle, be treated as an allowable cost in the future cost assessment process.

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[4] As detailed in Section 15 of the Connection and Use of System Code, User Commitment is the broad name given to the identification, assessment and payment of financial securities by parties who wish to connect and / or use the transmission system. [Connection and Use of System Code (CUSC) | National Grid ESO]

1.30 Noting that we do consider it may be appropriate for a developer to recover economic and efficient anticipatory investment costs through the relevant cost assessment process, we can see merit in the development of an assessment process specific to the eligibility of anticipatory investment. The purpose of this would be to determine the cost-benefit to consumers and providing developers comfort on their route to cost recovery where that consumer benefit is shown. It would also allow early analysis to protect consumers' interests from the risks of inefficient or stranded anticipatory investment by requiring a demonstration of the reasonable expectation that the future user or users intend to connect to the system (discussed further under question 4 below). Developers would at all times be required to demonstrate that costs incurred are economic and efficient as per current guidance. Further details on the process for anticipatory investment including proposed changes to cost assessment guidance will be the subject of future publications.

1.31 Development of an early stage assessment process would represent a change from previous policy where there was no such stage. Our previous position was that anticipatory investment risk was best allocated with the generator who would benefit from such assets. As noted above, the current regime is not delivering coordinated assets which could deliver real benefits to the consumers. The development of an early stage assessment process for developer-led anticipatory investment is part of the package of measures to facilitate greater coordination in offshore transmission assets where consumer benefit can be demonstrated.

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?

1.32 We received 29 responses to this question. Of these respondents, 20 suggested that the need for investment should be demonstrated through collaboration between the ESO, TOs and developers. Sixteen of those responses noted that the ESO, working in conjunction with the relevant TO(s), is the only party with the capability to identify wider system needs and assess the benefits of any investments proposed to address those needs.

1.33 We consider that the arrangement suggested by stakeholders is consistent with the existing ability of the ESO to propose wider network benefit investment (WNBI).[5] WNBI includes investment in offshore transmission assets or capacity that goes

[5] The ESO has been able to propose WNBI since the implementation of the Integrated Transmission Planning and Regulation (ITPR) project: final conclusions. [Integrated Transmission Planning and Regulation (ITPR) project: final conclusions | Ofgem]

beyond that needed by a single developer and supports the reinforcement of the wider system. 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.[6]

1.34 Responses to this question also flagged that the demonstration and assessment of the need for investment should account for factors that are not solely cost-related. The suggested factors included environmental criteria, local community impacts, consenting considerations, deliverability considerations, and wider socio-economic benefits. We expect that the assessment process will account for a range of relevant factors as well as our statutory duties to make decisions that are in the best interests of consumers.

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

1.35 We received 27 responses to this question. Stakeholders suggested a range of criteria including project agreements such a lease or an agreement for lease in the relevant seabed development area, consents or consent applications for onshore and offshore development, a connection agreement, a CfD or a power purchase agreement. It was noted that the option fees associated with an agreement for lease may strongly incentivise a developer to connect to the system in a timely manner. Eight stakeholders suggested that the arrangements for generation user commitment set out in Section 15 of the Connection and Use of System Code (‘CUSC’) demonstrate a reasonable expectation that a party contracted through a connection agreement intends to connect to the system. Given the feedback on applicable criteria above, and the time limitations of the Early Opportunities workstream, proposals on anticipatory investment under development will be those which have a specific project in contemplation. We note that there could be a different approach to the treatment of anticipatory investment for later workstreams.

1.36 Anticipatory investment is by definition investment which is taken ahead of being required and there will inevitably be some uncertainty around future projects. Application of a CfD as a metric would qualify only projects with a high degree of

[6] statement-on-the-proposed-framework-to-enable-coordination-an-update-to-our-december-consultation.pdf (ofgem.gov.uk)

certainty which would therefore circumvent the aims of the policy. However, as approving anticipatory investment and transferring the risk away from the first moving project will provide significant benefits to the projects involved, criteria will be developed to show that later projects have a reasonable expectation that they intend to connect to the system. Consumers will not be asked to assume risk for speculative future projects.

1.37 Under question 2, we have discussed phased assessments of any proposed anticipatory investment. These could be used not only to give developers comfort on their route to recovering anticipatory investment, but also to measure the likelihood of later projects connecting to the assets in question.

1.38 The feedback provided has been very informative and will be fed into the development of our proposals, details of which will be included in the next publication on Early Opportunities and is likely to include a mix of leasing and planning milestones.

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

1.39 We received 28 responses to this question. Approximately two-thirds of stakeholders broadly agreed with our proposals, with one third generally disagreeing.

1.40 Fourteen stakeholders noted that developer-led coordination of Early Opportunities projects will require sufficient incentives - either financial or by other means such as an accelerated connection date - as well as mitigation of any increased development risks faced by those projects as a result.

1.41 This feedback will be factored into the development of the policy changes with regard to anticipatory investment and charging which are discussed more fully above. Further details will be published in our next consultation.

1.42 Feedback was also received that changes to the CfD regime would also be beneficial to facilitate anticipatory investment within Early Opportunities. We are engaging with BEIS to explore policy interactions between the management of anticipatory investment risk and the CfD regime.

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

1.43 We received 27 responses to this question. More than half of stakeholders suggested that a Significant Code Review (‘SCR’) is not required to give effect to a potential decision to 'share' anticipatory investment risk between consumers and developers. Some of these stakeholders noted that the timescales typically associated with the SCR process would be a barrier to delivering timely code modifications to facilitate Early Opportunities projects. The need for code changes to be implemented in the early 2020s to facilitate projects planning to connect in the 2030 timeframe was highlighted.

1.44 Five stakeholders suggested that a Significant Code Review is required, given the complexity of some of the potential changes and the need to ensure they are progressed in a coordinated and timely manner.

1.45 Since the consultation, the OTNR Expert Advisory Group has established a sub-group to look at code modifications which may be required for Early Opportunities. The ESO is working in collaboration with industry to identify the changes required across the relevant industry codes. The engagement with industry has included code- workshops, other industry fora, and bilateral project discussions.

1.46 Our continuing expectation is that the industry-led governance processes set out in the respective codes will be used for the identified changes, given that the changes in this workstream are expected to be incremental rather than fundamental or wide-ranging.

1.47 In any implementation of risk sharing proposals, we expect the ESO will take the lead in developing and proposing the 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 the appropriate parties to propose the necessary modifications. We will engage with industry parties (and subsequent workgroups) that bring forward relevant code modifications.

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

1.48 We received 32 responses to this question. Stakeholders were broadly supportive of Ofgem's proposed approach to deliver the objectives of the Early Opportunities workstream.

1.49 Several stakeholders did not agree with Ofgem's proposed approach, suggesting that greater coordination would be delivered if it was obligatory instead of optional within the Early Opportunities workstream. One stakeholder highlighted that developers are not sufficiently incentivised to opt into any additional risk associated with a more coordinated approach within the timeframe of this workstream. We note that within the existing regulatory regime and this workstream, developers of offshore generation are not obliged to develop efficient, coordinated and economical networks. Our proposals in this workstream are intended to facilitate decisions by developers that will increase the level of coordination between in-flight projects and as such we will provide further details on these proposed changes in our next publication.

Annex 2 – Update on Pathway to 2030 Workstream

Workstream context

2.1 The objective of this workstream is to drive the coordination of offshore projects progressing through the Crown Estate (TCE) Leasing Round 4 (LR4) and Crown Estate Scotland (CES) ScotWind (and other appropriate projects) connecting to the transmission system by 2030. Projects from LR4 and ScotWind will help the UK to meet the government target for 40GW of offshore wind capacity by 2030 as well as contributing to the Sixth Carbon Budget.

2.2 To date TCE and CES have developed a Generation Map[7] that together with the modelling normally completed by the ESO (eg, the Electricity Ten Year Statement, Future Energy Scenarios etc) will inform the development of the Holisitc Network Design (HND). The ESO is expected to complete this exercise by the end of June 2022.

2.3 The final work area within this workstream, for Ofgem, is to develop and implement a model for delivering the required infrastructure.

Next steps for workstream

2.4 We intend to publish a decision on the Delivery Model for Pathway to 2030 during the Spring of 2022. We will then consult on how to implement that Delivery Model.

2.5 Between now and making a decision we will be continuing our analysis on which Delivery Model we intend to implement for the purposes of Pathway to 2030. Following our initial analysis, we have decided that we will focus on those models which do not involve a competition prior to the detailed network design process. This is because models entailing a competition prior to the development of the Detailed Network Design (DND) would require additional time for us to develop and then implement a tender process prior to the DND being completed. This means that 'early' competition models may put at risk delivery of the 40GW offshore wind target by 2030. This therefore rules out models four and five as included in our consultation.

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[7] Offshore Network Transmission Review generation map: GIS files and links to other publicly available data - GOV.UK (publishing.service.gov.uk)

2.6 In addition to focussing on 'late' and 'very late' competition models we will also assess a model that was not included within the consultation. This is similar to Model 3 in our consultation but instead of a TO doing the DND and Pre-Consent work this is done by a developer. This variant aligns with some of the responses we have received which suggest that Offshore Transmission Owners (OFTOs) could be involved in the delivery of infrastructure at an earlier stage as explained below.

Summary of responses to 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.

2.7 We received 44 responses to Question 8. Most stakeholders broadly agreed with our statement and agreed that the ESO should be responsible for developing the HND. Twelve respondents emphasised the need for the HND to consider onshore aspects when considering offshore coordination options. Five responses highlighted the need for the HND process to consider the annual Network Options Assessment (NOA) produced by the ESO.

2.8 Seven responses questioned how the HND could speed up later development steps, given that the planning and consenting processes (in England and Wales) are based on statutory timelines. We said in our consultation that we expected by demonstrating being part of a wider programme and being able to show the cumulative impact of development may aid planning applications.

2.9 Sixteen respondents expressed concern that the HND could lead to delays or increases in cost compared to a radial connection.

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

2.10 We received 34 responses for question. Twenty-two of these agreed with our proposals for an offshore DND, seven were neutral and five mostly disagreed with the planned work for detailed network design offshore. Some respondents emphasised the need for strong coordination between the onshore and offshore detailed design interfaces. One of these responses emphasised the need for expertise in HVAC electrical system interfaces and HVDC codes and standards. A few respondents questioned if the onshore works would be funded through the existing RIIO system.

2.11 The five responses that disagreed with aspects of or the whole DND process, were worried about technical risks of having different parties designing and constructing the assets. A few of these responses also worried about environmental and community impacts. These respondents wanted the environmental assessment criteria to be specified and one opposed coordinated efforts which would lead to the increased size of radial connection.

2.12 Most respondents also gave a view on who should undertake the DND offshore. Most respondents gave a view either for or against the incumbent TOs undertaking this activity. TOs were supported because of their onshore planning and construction experience. However, those who opposed the TOs having this role identified potential conflicts of interest arising from the TOs being both a potential designer and bidder to construct and deliver these assets. Respondents also flagged deliverability risks if the TOs were tasked with the DND. They noted concerns about potential delays as TOs were already stretched delivering their current obligations.

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

2.13 We received 38 responses to question 10. There was no consensus among respondents as to which party would be best placed to undertake the DND offshore.

2.14 Seven respondents suggested that whoever designs the assets should also construct them. This group focused on the need to limit interfaces between delivery partners. Three of this group noted that TOs might not have the required resources to undertake this work given their existing responsibilities.

2.15 Another group offered a range of options – from the TOs being responsible for the DND in its entirety to the TO being responsible for non-radial assets while the relevant generator or interconnector developers were responsible for other assets.

2.16 Other respondents noted that the ESO should undertake the DND and the HND to maximise synergies, minimise interface risks and reduce the scope for conflicts of interest. Other respondents were agnostic on which type of organisation should undertake the DND.

2.17 One respondent said that whichever organisation undertook the DND they should be technologically neutral, and that if different organisations were undertaking the DND and construction, then safeguards should be included to minimise the level of unnecessary redesign undertaken by the constructing party.

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.

2.18 We received 39 responses in total. Thirty-two responses agreed or mostly agreed with the developer-led model being retained where the HND indicates a radial solution should be used. These responses mentioned that developer-led radial connections had been proven cost effective, timely and that markets understand the existing regulatory mechanisms and frameworks. They also mentioned that developers have industry experience and that the developers know how to mitigate risk in the most efficient way.

2.19 Seven respondents disagreed with the proposal.

- An interconnector developer believed that radial solutions should only be adopted when all other larger vision options had been considered. These options included integration in an (transnational) offshore grid, development of an MPI or an offshore bootstrap.
- The environmental group, along with the four council groups, were worried about social and environmental impacts of further radial connections.
- A TO said this would risk minimising the level of coordination that might be achieved.

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.

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

2.20 Thirty-seven respondents addressed this question.

2.21 The table below illustrates where respondents expressed a preference for either a single option, or an option as part of a range of options. However, as there were seventeen unique combinations, we have not shown all of these. In the subsequent sections of this annex, we have summarised the views expressed with regard to each model.

	Mentioned as the preferred option	Mentioned as one of the preferred options in a response
Model 1	0	6
Model 2	0	5
Model 3	0	4
Model 4	1	3
Model 5	0	5
Model 6	10	5

Model 1

2.22 Some respondents are of the view that TOs are best placed to manage the onshore/offshore interface. Some respondents extended this view to include offshore grids and MPIs with other countries around the North Sea.

2.23 The points summarised below were also used by those advocating Model 1. These respondents suggested that TOs are best placed to allocate costs 'fairly' between parties, and that TOs are best placed to benefit from economies of scale. Respondents suggested that Models 1-3 could allow for consistent approach towards the environment.

2.24 A number of respondents were not in favour of Model 1. One respondent stated TOs have a strong track record for delivering offshore assets. However, it noted that "TOs are not currently set up or resourced to undertake detailed design or pre-construction activity for offshore assets." Building on this, ten offshore wind developers, an interconnector developer, two technology providers, an industry body and an OFTO doubted that the TOs could deliver the assets on time or economically. They cited reasons including lack of offshore consenting and construction experience and a lack of appropriate incentives – ie they did not see how TOs could be incentivised to ensure timely delivery.

2.25 One respondent thought that Model 1 could enable TOs to facilitate more coordination both offshore and onshore. A number of respondents were concerned with regard to the level of competition within this Model.

Model 2

2.26 Similar points are made regarding Model 2 as about Model 1. However, Model 2 was seen more favourably by some because it included a role for competition prior to operation. Adding to the points made under Model 1, OFTOs were viewed as experienced operational delivery partners by the majority of respondents.

2.27 An industry body remarked that to avoid delays, the OFTO tender could be run in parallel to the asset design work. They stated that TOs have consenting experience from an onshore perspective but that not owning the infrastructure disincentivises the TOs from delivering the assets on time.

2.28 One respondent thought that Model 2 may have less competitive pressure than Model 6 (at least under existing network charging arrangements) as whilst both Models have downward regulatory pressures, eg through the setting of allowances or the disallowance of costs which are not economic and efficient, the costs of offshore infrastructure are directed back at offshore generators (under Model 6) while this is not the case for the onshore TOs (under Model 2).

Model 3

2.29 A number of the points made in relation to the previous models were made in relation to Model 3, eg TOs not having a track record delivering offshore, interfaces between phases of delivery, and concerns about conflicts of interest etc.

2.30 Some respondents expressed their concern regarding OFTOs having a lack of construction experience. The respondents included four wind developers, one offshore wind investor, one technology provider, and one industry body.

2.31 Two OFTO responses argued that they have a strong track record in constructing assets. The first respondent noted their experience in delivering interconnectors. The second had gained relevant offshore experience from their experience in international projects.

Model 4

2.32 A limited number of respondents were in favour of Model 4 to some degree. They partially agreed with Model 4 because it included early competition. However, they did worry about early competition potentially 'locking in' engineering solutions and reducing project flexibility. Some respondents suggested that if Model 4 or Model 5 were selected then the TOs or the ESO should undertake de-risking activities such as survey work.

2.33 As with Model 3, some respondents expressed concern about the current OFTOs lack of experience and track record in designing, consenting, and constructing offshore transmission assets. However, as noted under Model 3, some OFTOs pointed out their previous experience internationally, or in relation to the delivery of interconnectors.

2.34 Some respondents felt Models 4 and 5 were more suitable for the Enduring Regime. A number of respondents noted that Models 4 and 5 may result in a significant delay in the DND being started thereby incurring associated delays on the rest of the process, delaying the overall deployment of offshore wind.

Model 5

2.35 Model 5 is seen by some as introducing innovation and competition while reducing process complexity. If an early competition is well designed and timed the view was expressed that this could give developers confidence. Some respondents also noted the benefit of the same entity designing, constructing and operating assets.

2.36 As with the Models 3 and 4, some respondents referenced the OFTOs' perceived lack of experience in construction.

2.37 As with Model 4 some respondents noted the risk of delay posed by this model. Some respondents also noted that there was a risk that changes required following any consenting process might require further changes to design that would not be subject to competitive pressures.

Model 6

2.38 Generally, generators and OFTOs are considered as experienced delivery partners for their respective roles in Model 6 as they are similar to existing roles for radial assets.

2.39 Proponents of Model 6 say that generators are experienced and naturally incentivised to deliver infrastructure on time, given the requirement as route to market for generation. However, some responses, including five offshore wind developers, argue that generators are incentivised to connect but not to coordinate their assets in the current Model. Some respondents queried how generators would be directed not to solely prioritise their own assets and incentivised to take on additional risk stemming from coordination. Some responses mentioned that limiting the number of interfaces, such as DND and OFTO tendering processes, will help de-risk the projects. Three developers pointed to Model 6 not needing legislative changes, reducing the risk of delays.

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

2.40 A number of respondents stated a preference for a Model 6 which would enable Joint Ventures (JV) between generators and/or OFTOs. One respondent also suggested a model where a third party was appointed to undertake the DND and Pre-Construction activities prior to construction and operation by an OFTO.

2.41 One respondent notes that Models 1-3 should be modified whereby the role currently allocated to the TOs is allocated to the ESO.

2.42 A number of respondents, including the ESO, stated that multiple delivery models could be developed to allow different competition models to be used depending on the infrastructure being delivered. One respondent also suggested that extending the TOs' transmission areas offshore would allow for the most coordinated solution.

2.43 One respondent noted that a 'lead' developer could be appointed for a given area, this developer would then have responsibility for delivering all infrastructure in the area for which it is the lead.

Annex 3 – Update on Multi-Purpose Interconnectors Workstream

Workstream context

3.1. This chapter of our consultation sought to gather evidence to support the policy options being explored by both Ofgem and BEIS in developing an interim and enduring MPI regime, respectively. The Early Opportunities chapter considered barriers common to all early opportunity concepts (including MPIs), and the MPI chapter sought views on the barriers specific to MPIs, ie licencing, asset classification, and ownership. The feedback received from stakeholders is summarised below.

Next steps for workstream

3.2. Taking account of feedback and analysis, we intend to publish a minded-to decision in Spring 2022 setting how we think we can adapt the existing licensing framework for MPIs on an interim basis. Assuming this is feasible, this will be followed by a decision and an implementation consultation in due course. In parallel, we continue to ensure alignment with the recent conclusions of our Interconnector Policy Review[8] and with BEIS in respect of considerations for a possible enduring MPI framework.

3.3. Comments received in response to the BEIS Question 1 have been shared with BEIS who are reviewing them as part of their enduring regime considerations.

Summary of responses to 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?

3.4. Twenty respondents answered this question. Nine respondents explicitly agreed that our consultation focused on the right models at this stage and no respondents disagreed. In respect of whether Ofgem should seek to facilitate multiple MPI models

[8] December 2021 ICPR decision: [Interconnector Policy Review - Decision | Ofgem]

– as opposed to only one – nine respondents said yes. Some stakeholders justified this view on the basis that the concepts, commercial application and regulatory landscape are still evolving and so we should not rule out models so early on.

3.5. Building on this theme, nine respondents stated that Ofgem should not rule out other potential models, such as energy islands, models that incorporate the electrification of oil and gas platforms, multi-national hubs and different jurisdiction led MPIs.

3.6. With regards to whether Ofgem should consider the evolution of MPIs from pre-existing assets, we received fewer comments on this particular question than the others. From the seven that addressed this topic, there was consensus that we should not rule it out. However, views were mixed on how likely it was that pre-existing assets in operation today could evolve into MPIs. Five of the seven respondents were of the view that the potential cost and complexity of technical challenges of retrofitting assets to become MPIs would be prohibitive. Examples given were that the routes or capacities of existing interconnectors may not be beneficial in respect of the siting of wind and that there is a technical need for electrical sharing of transmission assets to be planned from the early development phases of both generation and interconnector projects.

3.7. In contrast, only two respondents were of the strong view that both models could evolve from pre-existing assets. They pointed to the recently commissioned Kriegers Flak project between Denmark and Germany, which demonstrates how an existing offshore connection system can be enhanced to become an interconnector system[9].

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

3.8. Sixteen respondents answered this question. Ten respondents agreed with Ofgem's position set out in the consultation on ownership structure for MPIs in the current framework, ie that each component asset would require a separate licence and legal

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[9] Please refer to Appendix 4 of the Ofgem July consultation for Kreigers Flak case study. Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

ownership. Respondents also set out the importance of legislative change to better facilitate MPIs, in particular in respect of ownership structures.

3.9. One stakeholder stressed the benefits of joint operation and ownership stating that all elements of an MPI would operate in unison; which would reduce interface risk faced by all parties, including the third country interconnector investors and it would avoid the investment risk created by breaking assets down into smaller component parts, with different owners. This is a concern as it can affect risk and return ratio and make it harder to justify any investment upfront (which was seen as a big issue for first-mover projects).

3.10. While not disagreeing with the ownership point, three stakeholders made a series of other points in relation to the functionality of the current framework. One stressed the value in current arrangements whereby the developer of the offshore wind farm and the offshore link can be the same party (in the generator-build OFTO model) up until the point the OFTO asset is tendered, which ensures efficient coordination of assets, timely completion of generator construction, and timely security of the grid connection. Two respondents stressed that the key barrier in the Electricity Act 1989[10] was the inability for a generator to also own and operate transmission assets (beyond development and construction stages).

Question 16: What are the commercial, operational and regulatory factors that would drive a developer's 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?

3.11. We received 17 responses to this question. The purpose of this question was to help us understand whether the configuration of MPIs altered their intended usage in any way, or whether there were technical factors that dictated model choice.

3.12. Seven respondents directly addressed the topic of asset use depending on model type. All seven agreed asset usage would not vary between MPI models. The general view from responses was that either way, the assets of the MPI will do the same thing: when the wind blows, the MPI will convey that generation to shore, and any

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[10] Please refer to Table 5 in consultation document: [Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem]

excess capacity of the MPI would be used for cross-border exchange. When the wind isn’t blowing, the capacity available for cross-border exchanges will be higher.

3.13. Stakeholders shared views on the commercial and operational factors that might determine MPI model choice. Firstly, construction sequence was cited as a reason by five respondents. For example, existing radial links create the potential for connecting projects in neighbouring countries through the OFTO-led model. Conversely, where developers have the opportunity to create an MPI from design, they may be inclined to select the interconnector-led model as this would allow all non-generation assets to have a single owner and to be covered by same regulatory arrangements. It was also noted that choice could be driven by the economics of the first asset and whether further revenue can be created with limited additional cost of connecting the second asset.

3.14. Ensuring delivery incentives was another issue raised. Whichever model is used, wind farm developers will require that the infrastructure developer/owner has strong and suitable incentives, whether they are commercial or regulatory, to build the transmission infrastructure on time and ensure it is operational and reliable.

3.15. Stakeholders stated a number of factors that will influence whether to proceed at all with an MPI, irrespective of model choice. Five respondents stated that neither asset should be adversely affected – financially or operationally – by forming an MPI (compared with the status quo). For example, suitable commercial arrangements need to be in place for wind farm developers to consider utilising an MPI connection. If a developer were to be worse off operationally and financially, when compared to the status quo of a radial connection (or another coordinated solution), then there would be no incentive to develop the MPI asset. The interconnector should not be adversely affected either and there is a need for a viable commercial model so they see a return on their investment which is on a level playing field with (or better than) investing in a standard radial interconnector.

3.16. Four stakeholders highlighted the importance of ensuring key dependencies such as the granting of a CfD for wind farm project delivery were not disrupted by pursuing an MPI connection, stating that the wind farm would need to retain its grid connection, meet its stated delivery schedule, and comply with technology specific requirements to retain CfD eligibility. Other areas listed where further clarity is need include revenue arrangements (eg wholesale market revenue, imbalance prices, costs, compensation for delays and outages, eligibility for renewable support mechanisms and renewable certificates) and duration and firmness of grid capacity. Developers will prefer a model that gives clarity over these important elements.

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.

3.17. We received 16 responses to this question. None of the responses received stated that L1 would fundamentally be used differently as a function of the MPI model adopted, however, stakeholders noted various other factors that would influence usage. A common view shared was that the assets in each model will do the same thing, but the exact usage would depend on whether L1 has been sized to carry excess capacity beyond the output produced by the connecting wind farm and thus allow cross-border flows to be available at maximum wind output.

3.18. Six respondents shared their views on usage patterns in the scenario where L1 was not oversized. Two respondents highlighted that primary usage would be offshore wind transmission in the OFTO-led model; and two stated it would be offshore transmission in both models. Another respondent had the view that in the interconnector-led model, primary usage would be dictated by the market at any one point in time because offshore generation would be competing with cross-zonal flows via market mechanisms on a constant basis. It was also stated by one respondent that given wind farm load factors are typically around 50%, L1 would be available for cross-border trade 50% of the time and thus can be comfortably considered to fall within the interconnector definition.

3.19. Other views shared include concern that the primary use of the assets would change over time, highlighting the importance of an enduring regime that facilitates flexibility in asset usage over its lifetime, and that we cannot determine L1 usage until market arrangements and regulations are settled upon.

3.20. One respondent flagged that a key difference between the interconnector-led model and the OFTO-led model is that the ESO will retain its function for balancing and dispatching energy within L1 in an OFTO-led model, with the interconnector performing this function for an interconnector-led model.

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?

3.21. We received 15 responses to this question, covering a variety of themes. Four stakeholders noted that there were no major barriers in the industry codes preventing L1 being classed as an interconnector or OFTO while undertaking secondary activities. On the topic of codes, two stakeholders stated the need to consider and address whether the existing definitions for assets will allow for multi-use purposes. Finally, on codes, it was also flagged by one respondent that there is no existing arrangement that could be used to govern the connection agreements in the interconnector-led model, noting specifically that the Grid Code, Balancing and Settlement Code ('BSC') and CUSC need to be considered.

3.22. Another area of feedback flagged by two respondents was in respect of charging arrangements. It was noted that we should consider the treatment of TNUoS costs to ensure that MPI assets are not disadvantaged. We note that charging arrangements for all pathfinder concepts, including MPIs, is being considered via the Early Opportunities workstream.

3.23. A technical consideration was highlighted to us by two respondents, in that L1 will need to have bi-directional power flow which may not be compatible with existing requirements for an OFTO and should be considered.

3.24. Another issue raised by two respondents was that more information is required before barriers can be fully identified, both in terms of details on the assets and their functionality, as well as market arrangements.

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?

3.25. We received 14 responses to this question. Three stakeholders suggested Ofgem should exercise regulatory flexibility to accommodate the variation that is likely to be seen in MPI configurations at a project level. Three respondents stated there should be consistency with traditional asset regulation, ie a level playing field in regulatory reporting with non-MPI counterparts. Another stakeholder recognised that this might not be the case in the early stages but as the asset adapts the performance level of the assets should be comparable to onshore assets over time.

3.26. Another factor raised by stakeholders was the need to avoid creating new risks for early MPI projects. For example, one risk raised was generators potentially losing their route to market if availability standards are not maintained. Two stakeholders stated that any new reporting or administrative requirements must be practical, non-burdensome and add value.

3.27. Three stakeholders stated that there should be no changes to the wind generation regulatory regime. A potential concern raised here was that an MPI with long-term interconnector capacity contracts might restrict wind generation at peak wind times.

3.28. One stakeholder suggested we consider the provision of environmental evidence to align requirements to current licensable activities in the marine environment.

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?

3.29. From the 12 responses to Question 20, the most common view – from eight respondents – was that Ofgem could use its existing powers to transpose obligations across licences in order to regulate MPI activity within the current licensing framework. Stakeholders noted that Ofgem already has an effective approach in place that applies specific special conditions to OFTOs – special conditions specifics to OFTO Tender Rounds – and interconnectors – special conditions specific to projects where they apply for a cap and floor regime – which can be switched on and off as necessary.

3.30. We received a variety of comments in respect of key considerations. Three stakeholders specifically cautioned that we should carefully consider the 18-month Generator Commissioning Clause for MPIs. It was noted by one stakeholder that any obligations should be clarified ahead of the Financial Investment Decision point in a project to reduce perceived regulatory risk within the investment community. It was also raised by a couple of respondents that amended or new special obligations are likely to require variations on a project-by-project basis to ensure appropriate incentives are in place.

3.31. Two stakeholders specifically flagged that the interconnector licence could be easily adapted for the interconnector model, and we received some suggestions of key obligations to consider for an MPI: non-discrimination may need to be considered to ensure efficient and optimal operation of the MPI, allowing cross border flows to be optimised around wind outputs. Cap and floor regime approval dates (IPA and FPA), regime start dates, and longstop dates might require alignment with the host projects to ensure that MPI investment and construction for all assets can go ahead in parallel.

3.32. In terms of the OFTO licences, we received suggestions of key obligations to consider for an MPI: The 'Activities Restriction E12 – B2' clauses in the OFTO licence may need to be reviewed from an MPI perspective to ensure efficient operation of the whole asset – especially when aligning cross border flows with offshore wind production. We believe that some of the 'Separation and Independence of the Transmission Business E12 – C2' compliance obligations may need to be considered further. The 'Incremental Capacity Incentive Adjustment' may need to be considered if an MPI is connecting to an operational OFTO.

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?

3.33. We received ten responses to this question. We asked this question to understand whether there was any potential benefit in exploring the provision in Section 5 of the Act for the Secretary of State to grant exemptions for the requirement to hold a licence ahead of an enduring regime.

3.34. Six of the ten respondents said that it could provide a temporary solution in advance of an enduring regime. For example, in maximising use of L1 and L2 in situations when wind farms fall partly or completely out of service, or where Ofgem concludes that the existing Electricity Act definitions prohibit the use of either the OFTO licence or the interconnector licence. However, it was also identified by two respondents that using the exemption route would still require the identification of the asset's primary activity in order to make an accurate application to the Secretary of State for an exemption, and thus this facility in the Act does not resolve the present issue of which licence to grant.

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?

3.35. We received 13 responses to this question. On the topic of Article 16(8) of the EU's Electricity Regulations, five respondents suggested that the requirements of this article[11] would influence the best choice of MPI model. Three suggested that derogations from this requirement should be applied to MPIs where necessary, and that these would likely be needed for the Home Market (HM) model. In respect of the Offshore Bidding Zone (OBZ) model, three respondents suggested it would eliminate the issue that arises from the requirements of this article, as generation capacity sent to either connecting market would be considered cross-zonal capacity. Further, a couple of respondnets suggested it would allow for the more efficient use of MPIs. One respondent flagged that a key factor in efficient use is the use of implicit capacity allocation.

3.36. On the topic of Article 12 of the retained Electricity Regulation 2019/94312, it was raised by three respondents that new offshore wind farms would no longer benefit from priority dispatch. One went on to say that priority dispatch would be incompatible with an OBZ model as non-discriminatory access should be granted on interconnection assets. Building on this point, it was raised by two respondents that priority dispatch would not be necessary in a future where a large share of the electricity system is made up of renewable energy sources. In contrast it was also suggested by another stakeholder that priority access to the grid would be necessary to ensure that the maximum amount of renewable electricity is utilised.

3.37. In respect of Article 13 of the retained Electricity Regulation 2019/943 two stakeholders raised the point that it requires renewable generators to be curtailed only as a last resort, which will have an impact on the MPI model chosen. It was also noted by another that this article obligates TSOs to limit redispatch for renewable generators to 5%, unless electricity from power-generating facilities using renewable energy sources or high-efficiency cogeneration represents more than 50% of the annual gross final consumption of electricity.

3.38. In contrast, two stakeholders noted that the Trade and Cooperation Agreement between the UK and EU (TCA) sets out that interconnector capacity must be maximised and should only be curtailed in emergency situations. Ofgem notes that

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[11] Article 16(8) of Regulation (EU) 2019/ 943 on the internal market for electricity 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.

[12] The Electricity and Gas (Internal Markets and Network Codes) (Amendment etc.) (EU Exit) Regulations 2020 (legislation.gov.uk)

these two may be competing regulatory requirements upon development of MPIs, and that further consideration is needed when developing the market arrangements governing them.

3.39. It was raised by two respondents that all arrangements should apply equally to MPIs and radially connected offshore windfarms so that an MPI asset is not disadvantaged under any new regime.

3.40. Making a similar point on consistency in regulatory treatment, one respondent also raised the point that currently offshore wind projects pay TNUoS charges for the use of the transmission assets, whereas TNUoS is not payable by interconnectors. It was suggested Ofgem should ensure consistency in the TNUoS charging arrangements for offshore windfarms connected radially and via MPIs.

3.41. Finally, it was also identified by one respondent that the consenting regime for the development of offshore infrastructure might need consideration. The stakeholder noted that MPIs may not be an exempt cable under Section 81 of the Marine and Coastal Access Act 200913, and that consideration is needed as to whether the projects would be subject to an Environmental Impact Assessment.