The voice of the energy industry

Energy UK Response to Ofgem's Call for Input on a Future Strategic Approach to Interconnection

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About Energy UK

Energy UK is the trade association for the energy industry, representing companies investing billions of pounds to secure our country's current and future energy needs.

From growing start-ups to major electricity generators, grid and infrastructure developers, and energy suppliers, our members are driving change across power, heat, transport, and flexibility.

We provide a collective voice for the sector working with governments, regulators, charities and other organisations to provide crucial insight that shapes policy, offers solutions and promotes best practice.

Our broad view across the whole system supports evidence-based positions which are not tied to particular technologies, and are focused on delivering strategic benefits for people, businesses and the economy.

We champion initiatives such as our Vulnerability Commitment, which pushes suppliers to go beyond regulation to support customers with additional needs, and TIDE, the industry's drive for greater inclusion and diversity. Through our Young Energy Professionals Forum, we support the development of future leaders.
We are equally committed to our team and are proud to be recognised as a 'Gold' Investors in People employer.

Executive Summary

Energy UK supports Ofgem's ambition to evolve the delivery of interconnectors toward a more strategic, coordinated model. We agree that reform is necessary to reflect the increasingly central role interconnectors play in delivering a secure, resilient, and decarbonised energy system. However, the success of the Future Delivery Approach (FDA) will depend on clearer prioritisation of objectives, effective integration with spatial planning, and strong alignment with European frameworks.

While the proposed Criteria for Success are broadly appropriate, Energy UK considers that they should be explicitly prioritised. Above all, interconnector delivery must provide value for money for consumers, alongside ensuring security of supply

and system resilience. Objectives such as attracting investment, enabling competition, and fostering innovation should be treated as enablers of these core outcomes. The framework should also be more clearly anchored in Ofgem's statutory duties and take a more systemic view of interconnection within the wider energy system.

We are concerned that Ofgem's position to discount very early competition models may risk suboptimal development of project options. Introducing competition at the outset allows developer expertise to contribute to system optimisation and cost efficiency. Unlike other energy assets, the developer-led model for interconnectors has been one of main success stories of recent times in the energy system. There is nonetheless a need to marry the expertise of developers with more robust central planning. The FDA should therefore be closely integrated with the Strategic Spatial Energy Plan (SSEP) and Centralised Strategic Network Plan (CSNP), with early and ongoing coordination between NESO, European TSOs, and industry to ensure deliverable and well-located projects.

Clear and proportionate allocation of responsibilities between public bodies and developers will be critical. Energy UK supports NESO leading on system need identification and early-stage analysis, but considers that optioneering, design, procurement, delivery, and permitting should remain with developers. Public bodies should avoid overextension into later project stages, which risks undermining the benefits of competition and private sector expertise.

In terms of delivery routes, more coordinated approaches—such as Strategic Windows or well-designed tender processes—should be the norm going forward though a route for *ad hoc* projects should remain for projects of interest identified outside of SSEP/CSNP windows. Regardless of the model adopted, sufficient lead times, clear entry criteria, and alignment with connection processes will be essential to support effective participation and high-quality project development.

Given the inherently cross-border nature of interconnection, alignment with European regulatory, planning, and financing frameworks is essential and we fear the call for in out underestimates the complexity and depth of alignment and engagement required to develop deliverable cross-border projects. Energy UK emphasises the importance of coordinated spatial planning, credible cost- and revenue-sharing arrangements, and regulatory clarity across jurisdictions. Approaches such as *ex ante* cost-sharing with *ex post* adjustment for hybrid assets provide a promising balance between investment certainty and fairness. Strengthening cooperation with European institutions and frameworks will be key to enabling timely and investable projects.

Maintaining investor confidence during the transition to a more strategically planned system will require clear timelines, early regulatory certainty, and a well-defined end

state. The cap and floor regime remains an effective foundation for financing interconnectors but should evolve to reflect increasing project complexity and risk. This includes greater flexibility in revenue floors, milestone-based regulatory adjustments, preliminary funding, and differentiated treatment for novel asset types such as hybrid interconnectors.

Energy UK also highlights a number of emerging challenges that require policy attention, including persistent HVDC supply chain constraints, increasing technical and geopolitical risks, and gaps in current approaches to permitting, decommissioning, and asset lifecycle management. There is also a need to maximise the utilisation of existing infrastructure and to better account for the full system value of interconnectors, including their contributions to resilience, decarbonisation, and wider economic benefits.

In summary, Energy UK supports the direction of travel toward a more strategic and coordinated approach to interconnection but cautions overreach by public bodies with less expertise than developers. To succeed, the FDA must prioritise consumer value and system resilience, integrate effectively with spatial planning processes, align with European frameworks, and strike the right balance between risk allocation and investor certainty.

Kind regards,

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Response

Q1. Do you agree that these Criteria for Success cover the most important aspects of future interconnector delivery? If not, why? Are there other Criteria for Success that we should consider?

Overall, the criteria appear sensible. However, it would be wise for Ofgem to consider a hierarchy of these criteria instead of treating them as a list with equal weighting. For instance, above all, Ofgem should be ensuring the approach to interconnectors

provides value to money for consumers above all else. This priority should be matched by criteria on enable security of supply and resilience given the increasingly important role of interconnectors in these areas. Attracting investment and enabling competition and innovation should enable these objectives. In turn, enabling these areas should be done with consideration of European regulatory alignment and desirability in the neighbouring market.

If there is to be a set out criteria for the new approach to interconnectors, it must be mor systemic and centred squarely on Ofgem's core duties than what is currently presented.

Q2. Do you agree with our view to discount both a very early and very late competition model in the delivery of future interconnection?

Energy UK understands this assessment and Ofgem's reasoning. However, eliminating the role of very early competition at this stage puts pressure on NESO to optimally consider the locations of future interconnection at the outset.

It would mean the suggested Future Delivery Approach (FDA) must be integrated at before the very early stage of planning during the development of the Strategic Patial Energy Plan (SSEP) given it is intended to inform the Centralised Strategic Network Plan (CSNP).

This would be in addition to the other criteria the SSEP is already considering in the SSEP exercise, namely cost, GB and European system optimisation, distance to onshore network, environmental considerations, and local societal impacts. It is worth noting that it will be left to the CSNP to consider whether an SSEP interconnector project is best delivered as a point-to-point or offshore hybrid project according to the final SSEP methodology. If this is done, careful consideration of the spatial plans in European markets would need to be considered at the outset to ensure the feasibility of identified landing points. Close coordination between the European Transmission System Operator (TSO), NESO and industry is needed when developing interconnection.

We support the intent behind a more centralised approach to GB energy system planning, particularly to improve clarity on overall system need and network design. However, the delivery of cross-border infrastructure is inherently complex and depends on mutual flexibility and close coordination between delivery partners to align processes, approvals and timelines on both sides of the border. This complexity needs to be reflected in any future delivery framework.

Experience shows that this depends on sustained cooperation over time, including iteration, compromise and close coordination between developers, system operators and regulators. These practical delivery requirements are not fully reflected in the consultation, and we are concerned that there is insufficient articulation of how the UK intends to continue working with European counterparts within a more centralised planning framework. As a result, some of the options under consideration could introduce delivery risk for future offshore and interconnector projects where they do not sufficiently account for European processes.

The current UK developer-led delivery model has a strong track record of progressing interconnectors through close coordination with European TSOs and regulators. Preserving the elements of this model that are proven to work is important to maintain delivery confidence and effective cross-border collaboration.

We therefore support a delivery approach that aligns with strategic planning by building on the successful developer-led model. In this context, Energy UK favours a very early competition model, in which developers bring forward projects in response to identified system need from the SSEP rather than competing to deliver a centrally specified solution.

In practise, this should be delivered primarily through cyclical regulatory application 'strategic windows'. Under this model, developers would bring forward projects that respond to identified system needs from the SSEP, rather than competing to deliver a centrally specified solution. This enables developers to apply their expertise and cross-border relations to develop innovative, efficient solutions that deliver consumer value and system resilience. NESO can then effectively evaluate which solutions achieve its objectives and are feasible, prior to considering options for the CSNP. Under both routes, developers should remain responsible for early project design and engagement with European counterparts. This reduces the risk of late redesign, supports timely delivery, and improves certainty for consumers. All projects would continue to be subject to a robust needs case assessment, with approved projects feeding into and refining future system plans.

Importantly, a degree of tolerance for justified variation against strategic parameters will be important to reduce delivery risk.

Alongside this, there should remain a case-by-case route for projects that are clearly in the national interest but cannot realistically wait for, or fit within, strategic planning cycles - for example, where there is strong government backing or a time-critical cross-border opportunity.

Q3. Do you agree with the way in which we define competition types?

It is appropriate to consider the stage at which competition occurs for now. Once this is established, the exact manner of competition can be consulted and decided upon.

As stated in our answer to question 2, we favour cyclical regulatory application windows as the approach to competition at a very early stage.

Q4. Are there any additional key development stages of interconnection delivery that we have excluded from Figure 1?

Generally, the stages indicated in Figure 1 are appropriate though it might benefit from greater granularity. For instance, preliminary surveys and desk research involves six figure ordnance surveys, provision of space survey reports and technical data of a project. A connection agreement involves multiple stages; an application, creation of timelines, initial meetings and discussions, payment of fees, initial and detailed design, disclosure of Transmission Entry Capacity (TEC). Similarly obtaining consents and seabed leasing involves multiple stages.

It is important for Ofgem to more granularly consider where exactly competition occurs.

Q5. Do you have a preference on the type of competition we enable through the FDA? If so, why? Where do you see the role of the procuring body ending and project developer beginning for your preferred competition type?

Energy UK believes that a very early competition is a preferable competition model.

This is because, more so than other infrastructure, the development of interconnection options is best developed and proposed by developers in close coordination with TSOs in other markets at an early stage before being subject to screening and needs case assessment.

The need for adaptability and flexibility with design options at a very early stage is essential.

Q6. How could responsibilities be divided between the public bodies collectively (i.e. Ofgem, DESNZ and NESO) and the project developer across early-stage activities (identifying need, defining parameters, enabling landfall/route options) versus later stage activities (procurement, assessment, delivery oversight)?

Given the shift towards more central planning, it makes sense for NESO to lead on system need identification and perhaps preliminary surveys and desk research. Modelling landfall options as part of the SSEP will also help define the parameters for future interconnection but this must be done with careful consideration of how the future commercial and spatial plans from energy stakeholders in neighbouring markets are developing.

However, beyond this, design, procurement, delivery and the obtaining of a connections agreement and associated permit should be obtained by the developer.

Ofgem should continue to provide regulatory approval and NESO to provide connections agreements.

We strongly encourage the public bodies not to overreach their responsibilities and note that the figure presented in this section of the consultation appears to indicate that under early competition, one of the public bodies would hold responsibility up to (or potentially even including) the obtaining of a connection agreement. While we do not feel completion should occur too early in the development of interconnectors, the visual indication of what competition would look like in this consultation document overreaches the role of public bodies.

Q7. What are the key benefits and risks of each of the proposed approaches, and do you have a preference towards a delivery route? Please explain your reasoning, with reference to any examples from previous interconnection windows, if applicable.

There is a need for a more forward-looking and coordinated approach to developing and selecting a pipeline of interconnector projects. A Strategic Window would be a fairer and more coordinated process and would be easily integrated with the new connection process which assess both project maturity and strategic need.

Nonetheless, we think there should remain a route for projects to progress alongside the strategic planning framework under exceptional circumstances. This is particularly important where evidence suggests that an opportunity has not been fully captured within a given SSEP/CSNP planning cycle and where a project can demonstrate high societal value and strategic international importance.

A tender process could deliver against system needs but might prioritise cost limitation against other factors. This means that the alignment with strategic needs would need to be clearly defined by NESO in those allowed to bid well before the tender process. This risks serious overreach by NESO and/or Ofgem into an area

where their expertise and adaptability to evolving design needs remains more limited than developers.

Q8. What would be the expected period from the CSNP outputs to the start of an application process?

The first CSNP is due to be delivered at the end of 2027. From there, the application process should be harmonised to the new, bi-annual connection gate windows for generation projects.

The period from final CSNP publication to application opening should be no less than 18-24 months for a strategic window or tender process. Criteria should be published at least 12 months prior to any window closing to give developers sufficient time to to develop compliant bids.

Q9. What additional factors should we consider to future proof the delivery model and regulatory processes, particularly in relation to managing design variations?

Technology neutrality should be engrained within the delivery model.

Further, consideration of alterations to the SSEP/CSNP process in the future should be mitigated against. The more the delivery process can operate independently of the minutiae of the centralised spatial planning process, the more future proof it will be. It is for this reason an early competition model is preferred.

In addition, one of the key issues with the information presented is that it fails to address how the SSEP is inherently high level, providing limited scope for granularity for interconnectors which have much longer lead times.

Furthermore, one of the risks that should be mitigated is the potential for a top-down bottleneck. If projects can only happen if NESO models them perfectly, this could likely ignore the market's ability to determine better landing sites.

Q10. What measures should the FDA implement to effectively address the needs of various asset classes?

As stated previously, ensuring technology neutrality in assessing options for delivering system needs is key.

It will also be necessary for the FDA or the early SSEP assessment of landing zones to consider European spatial plans and the EU-wide TEN-E network plan in order to

ensure harmonisation of network pans and the fair assessment of all types of offshore interconnection methods.

Q11. Are there any specific adjustments that should be made to the delivery approach for MPIs to account for wind leasing rounds? Are there additional development differences for MPIs that require changes to the delivery strategy?

At the outset, the delivery model should treat hybrid assets alongside point-to-point interconnection but should, during project selection, ensure that cost optimisation criteria do not preclude the opportunity for a hybrid offshore asset, given the potential for overall system savings.

Q12. How should our future approach to interconnection align with European regulatory and financing frameworks and cross-border governance to ensure regulatory clarity, investability and timely delivery?

The regulatory, financing and governance architecture for North Seas offshore development is only coherent if it is built around clear, coordinated frameworks at the outset, both for planning and for revenue management.

Offshore TSO Collaboration's (OTC's) proposal for an *ex ante* scenario planning approach with *ex post* adjustments for hybrid assets is an important first step regarding the latter. *Ex ante* means that countries determine their share of costs before the project begins on the basis of jointly modelled scenarios, an important step in enabling reliable investment decisions at an early stage. *Ex post* allows these shares to be adjusted after commissioning, when real data shows how much individual countries actually benefit. Combining both elements creates a system that is reliable enough to trigger large infrastructure investments while remaining flexible enough to fairly reflect the actual system benefits.

Because it is likely that no single financing framework will work, possible elements of such a financing approach must account for public loans, private financing, green bonds, guarantees, hybrid instruments or grants to close financing gaps. It is crucial that cost-sharing agreements and regulatory frameworks are reliable and designed for the long term. Only then can sound investment decisions be made and capital mobilised on a large scale.

Such an approach should address the considerable differences in ownership structures, regulatory systems and revenue models among TSOs in the North Sea. The aim must be to establish an integrated process for planning, cost sharing and financing with governments, national regulatory authorities and TSOs. The two key

areas to address first here is to ensure mutual recognition for a project of the relevant member state's regulatory regime and to agree a uniform approach, in the with relevant EU, member state and UK legislation, the use of congestion revenues.

Q13. What challenges and mitigation measures should be considered when coordinating with other TSOs?

Challenges will include the politics of negotiating the sharing of benefits and application of EU rules on managing congestion revenues.

Such issues should be managed in the long-term through the cooperation of relevant TSOs, regulators and governments through the North Seas Energy Cooperation (NSEC) body, Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) body.

In the immediate term, such considerations must be clearly agreed upon as part of the UK's and EU's work to couple their electricity markets and subsequently agree upon interconnector revenue management and operation rules.

A challenge to consider is that these very rules within the EU are currently being revised as part of the ongoing Grid Package and Capacity Allocation and Congestion Management 2.0 (CACM 2.0) policy initiatives. This makes the work of harmonisation something of a moving target for the UK.

Q14. What can be learnt from other jurisdictions' approaches to interconnection planning?

With respect to preliminary studies, considerations should include the technical reality of grid connections beyond the desired capacity and focus on a range of factors including technical, fiscal, security, social and environmental impacts on the communities that the project seeks to serve. Because of the particularly long development time of interconnectors, and the high amount of political will required for them to get built, governments may need to facilitate this lifecycle stage. Ostensibly, from this consultation, the UK Government intends to do this work themselves in a hands-on manner, rather than creating a very clear process for the full lifecycle development of projects by the private sector.

EU projects of Common Interest (PCIs) are a good example of how to establish suitable projects and get preliminary financing. The work on PCIs is coordinated by regional groups, dedicated to electricity, offshore grid development and more. They are intended to help the EU achieve its energy policy and climate objectives. Projects identified as PCIs benefit from accelerated permit granting, improved regulatory

conditions, lower administrative costs, and increased visibility to investors. Critically, PCI projects are able to receive European Commission Connecting Europe Facility (CEF) funds to be realised. Due to the exit of the United Kingdom from the European Union, projects originating in the UK are no longer eligible for PCI status. Energy Uk would emphasise the importance of this state of affairs being reversed in order to help increase investor certainty and capital availability for new interconnection projects.

Key projects in other North Sea countries, like the Celtic Interconnector between the Republic of Ireland and France, which was awarded €530.7 million from the CEF, after receiving PCI status, to complete the design and delivery of the Celtic Interconnector by 2025 and has also received EU funding at earlier planning stages.

Regarding feasibility studies, these should involve all relevant stakeholders, consider the benefits of a project as part of wider power system plans, and be conducted by one or more credible third party/parties or done in-house and should include a wide range of technical, economic, and social implications of interconnector development. The UK's own Holistic Network Design (HND) and CSNP process provides a good basis for this. Other international examples include the feasibility study for the Tun-Ita interconnector between Tunisia and Italy. This project was considered in the wider ENTOSO-E Ten-Year Network Development Plan (TYNDP) and is being considered in the context of wider regional grid support efforts in North Africa as the feasibility of the project is intimately connected to the successful development of the Tataouine solar plant and further interconnections Tunisia is developing with Algeria and Libya.

Another consideration should be the consideration of social economic welfare of an interconnector project, including consumer surpluses, producers surpluses and congestion income. The Gulf Undersea India Transmission System provides a good case study of this as it holistically considered the differing benefit motivations of both India and the Gulf States. India stood to benefit from cheaper, lower carbon electricity to relieve network constraints, while the Gulf States benefitted from a new revenue source and an incentive to build more low carbon generation.

Approval mapping at a project's outset is also essential. In order to agree preliminary financing, there must be agreed planning, agreed regulation, agreed permitting, and agreed permit mapping. Stakeholders should be consulted throughout the process. Projects that receive a major project status will streamline the permitting and grant review process. The counterparty for the revenue contract is really important for financing. A developer will often want a sovereign entity to guarantee revenues.

Australia's new Renewable Energy Zone (REZ) network operator programme, covering New South Wales, provides a good example of approval mapping and developing revenue certainty. In the REZ, the government vehicle is the revenue

counterparty to the transmission operator, collecting the transmission fees on their behalf. REZs are complex and multi-faceted, involving a combination of careful strategic planning, technical and regulatory design, community engagement and industry-focused policies and programmes.

Nonetheless, it must be noted that across project development, financing modalities, cost sharing, project implementation and execution, monitoring, regulation, decommissioning, and assessments for extending the life of a project, the UK's approach to interconnection is often cited as an exemplar worldwide.

Q15. Do you have any other views or proposals on the future of interconnection delivery that we have not yet considered?

There is currently a global HVDC cable production capacity gap of roughly one third of what will be needed to meet demand by 2030. Beyond initial construction, supply chains must sustain an interconnector across its entire operational life, which may span 50–65 years and cycle through 15-20 generations of technology. We propose that government policy should actively support the development of domestic or allied-nation HVDC supply chains, and that project developers be required to demonstrate long-term supply chain strategies, including spares holding and maintenance capability, as part of their regulatory approval process. The current "fix and fail" approach of relying on vendors for replacement parts poses a material risk to security of supply that policy has not yet adequately addressed.

Further, historically, decommissioning and end-of-life obligations are rarely considered at interconnector project inception. We propose that interconnector licence applications should include a credible decommissioning plan from the outset, including provisions for seabed restoration, component recycling, and cost allocation between parties. Permits should be considered for a duration that exceeds even the most optimistic estimate of technical life. This would also help attract longer-horizon institutional investment.

On permitting, most national permitting regimes were not designed with two-way cross-border interconnectors in mind. Regulatory reform in this area could dramatically reduce development timelines. We know that the OTC is looking at reviewing the cross-border permitting landscape with the aim of producing a standardised permitting pathway. We emphasise the need for dedicated, cross border political attention to achieve this. Reintegrating the UK into the PCI framework would help this.

Further, the ability for new generators to connect to an existing interconnector, thus essentially turning into a hybrid asset, does not exist. In high-congestion corridors

(such as the North Sea), where new cable routes face environmental, magnetic field, and seabed competition challenges, maximising the utilisation of existing infrastructure is essential. We propose that open access obligations, with a power flow study requirement before any new generation is connected, be built into interconnector licences from the outset, ensuring the maximum regional benefit from each cable laid.

Benefits such as reduced network congestion, enhanced competition, facilitated renewable integration, and job creation are real but routinely excluded from formal cost-benefit analyses used in regulatory decisions. We propose that a standardised secondary benefits methodology be developed and adopted across regulatory frameworks, so that interconnectors are assessed on their full economic and social value, not merely on congestion rent and consumer/producer surplus.

Finally, the Celtic Interconnector offers a precedent worth scaling. It incorporated a fibre-optic communications link alongside the power cable. As interconnectors open new subsea and overland routes, there is an opportunity to co-deploy digital infrastructure, data cables, and potentially even hydrogen pipelines along the same corridor. We propose that planning policy formally require developers to assess co-deployment opportunities as part of feasibility studies, and that government coordinate across departments (energy, telecoms, transport) to enable multi-use corridor development. This would improve the economics of individual projects and reduce the cumulative environmental footprint and administrative burden of multiple infrastructure corridors.

Q16. How can we maintain investor confidence during the period of transition from a developer-led to a more strategically-led approach to interconnection planning and delivery?

Clarity for interconnector and offshore asset developers on the sequencing of the SSEP and CSNP's proposals for system needs and the implication for their proposed projects is a key first step for investor certainty.

Two additional elements required to maintain investor confidence would include clarity on the end-state of the framework, as well as commitment to timelines.

Q17. What factors would make interconnection projects attractive to investors in a centralised, strategically-planned energy system?

Key to making central planning for interconnectors work is the consideration of how the SSEP and CSNP's approach will consider the approach taken in neighbouring

markets and how the framework might fit into the ENTSO-E TYNDP and the OTC's currently ongoing work to create an energy plan for the North Sea.

In addition, investors need revenue certainty, competitive risk-return balance, clarity on the planning pipeline and protection from political and regulatory change risk. The shift to strategic planning will reduce some of these risks but may introduce new ones such as political cycle risk. Mitigating some of these risks will be crucial to keep an attractive investment landscape for investors.

Q18. In developing the new financing approach, how should we balance predictability and certainty for investors and developers, with the need for project-specific flexibility?

Interconnectors are among the most capital-intensive and long-lead infrastructure assets in the energy system. Their development timelines routinely span a decade or more, crossing multiple political cycles and regulatory reviews. Investors and developers therefore require a high degree of revenue predictability to commit the equity and debt needed to reach financial close. At the same time, no two interconnectors are alike: they differ in route complexity, the regulatory maturity of connecting jurisdictions, counterparty creditworthiness, and the geopolitical environment through which they pass. A financing framework that is too rigid will fail to work for a large proportion of projects; one that is too flexible will fail to attract the institutional capital that deep, liquid debt markets provide at scale.

The right answer is not a single regime but a tailored financing architecture that provides a stable, predictable baseline while allowing structured, bounded flexibility at defined points in the project lifecycle.

Privately developed projects are greatly assisted by the availability of development grants and predictable revenue frameworks. The UK's cap and floor regime demonstrates that a regulated revenue floor — underwritten by bill payers — can unlock beneficial investment by reducing the risk that developers are unable to generate sufficient revenues to service their debt.

This core mechanism should be preserved and potentially extended. For new interconnector markets or first-of-a-kind connections, where price differentials and congestion rents are hardest to forecast, a floor-only instrument (without an immediate cap) in the early operational years may be appropriate to attract initial investment, with the cap phased in as market conditions stabilise. This mirrors the principle that revenue certainty is most critical in the highest-risk phases.

Flexibility should be structured around the formal regulatory milestone gates that already exist in well-designed regimes. The UK model illustrates this well: the Initial Project Assessment, Final Project Assessment, and Post Construction Review each allow the regulatory parameters to be updated as project costs and risks crystallise, without undermining the fundamental investment case.

This approach should be formalised and extended. Project-specific factors, such as unusual geotechnical conditions, currency risk in cross-border financing structures, or the need to underwrite a supply chain commitment in a constrained HVDC market, can be accommodated at these gates rather than through ad hoc negotiation. This preserves predictability for investors while allowing regulators to reflect the genuine specifics of each project.

The sequencing of certainty matters as much as its content. Specifically, in order to agree preliminary financing, there must be agreed project economic and system assessment, agreed planning, agreed regulation, agreed permitting, and agreed permit mapping in that order. Financing cannot be structured in a vacuum; investors will not commit to detailed project development expenditure without confidence that the economic assessment and regulatory and planning environment is settled and agreed upon.

This has a direct implication for the design of any new financing approach: regulatory certainty must arrive earlier in the development timeline than has historically been the case. At present, many developers absorb significant development-phase risk, commissioning seabed surveys, legal structuring, and supply chain bookings, before the regulatory and financing framework is confirmed. The shift to centralised spatial planning in GB, as well as most neighbouring markets, opens the opportunity to address this issue. Any financing model should be explicitly linked to the central planning stage.

Vehicles of cooperation should be built at both the technical and political levels before significant capital is committed. It is for this reason that reestablishing the UK's formal role in NSEC, ENSTSO-E and ACER is so essential.

Further, in practice, this means that intergovernmental Memoranda of Understanding and joint feasibility studies should be recognised as formal inputs to the financing gateway process, not merely background documents.

Q19. What are your views on anticipatory investment, and how can its potential benefits and risks be balanced to protect the interest of consumers?

Anticipatory investment, the likes of which developed in GB as part of the Accelerated Strategic Transmission Investment (ASTI) process, as well as the recent RIIO-T3 determinations and the still developing Electricity Network Sector Growth Plan, should absolutely be considered in interconnector planning.

The key challenge to developing anticipatory investment in balance with potential stranded investment, and thus unnecessary costs to consumers, is unique for interconnectors. That is because, while it already difficult for anticipatory investment to help inform the development of onshore networks, this can be addressed through centralised strategic planning by a public body. On the other hand, interconnectors require centralised planning by public bodies across various jurisdictions. This involves agreement on planning principles, assessment frameworks, political objectives and so on.

Addressing this risk means early agreement on common offshore spatial planning frameworks. It is for this reason that OTC's work to develop this is so essential and why it is important the UK's role in NSEC must be fully restored to ensure the UK has a formal voice in the room.

Further, once joint spatial plans are established, it means the development of joint supply chain procurement frameworks across the UK and its neighbours. This will help pool the buying power of European nations for key supply chain components and avoid unnecessary and uncoordinated competition for kit. Such a process is currently being worked on through NSEC but requires high-level political agreement and potentially years of negotiations that the energy sector can ill afford. Concerted political effort in this area is therefore vital.

Q20. We are starting from the position that the Cap and Floor model remains the most suitable financing regime for P2P interconnectors. How has the risk profile of P2P interconnectors changed since the introduction of the Cap and Floor model, and how should this be reflected in the future financing model?

The risk profile of electricity interconnectors has evolved from relatively straightforward, point-to-point infrastructure projects into complex, high-stakes assets facing intensified technical, market, and geopolitical risks due to their central role in the energy transition. Key shifts include increased operational difficulties, supply chain constraints, and the heightened security risks of cross-border dependency.

As projects move into deeper, harsher marine environments, they face greater maintenance, repair, and corrosion challenges. The increasing use of advanced, sometimes unproven, HVDC technology (like 525 kV XLPE cables) adds to the risk of technical failure.

Further, a surge in global demand for interconnectors has led to bottlenecks in manufacturing high-voltage cables and converters, resulting in potential delays and increased project costs.

Geopolitical risks have also increased, as recently exemplified by Russia's recent naval activity in the vicinity of North Sea energy infrastructure, as well as the recent sabotage of interconnectors in the Baltic Sea.

Interconnectors are also becoming increasingly important for system resilience. Interconnection will enable greater cross-border system balancing and renewable deployment when simultaneous weather events do not occur or/and when a high degree of low carbon firm capacity, like nuclear energy, is deployed.

The delivery of hybrid offshore assets, which are novel, also needs to be considered.

Market and policy-support changes are also causing uncertainty to developers as to the viability of projects. Namely, the increase in curtailment and constraint costs, uncertainty over the level of renewables rollout due to supply chain constraints and rising projects costs, uncertainty over the direction of market reform in jurisdictions like Reformed National Pricing (RNP) and the SSEP/CSNP in GB and difficulties in projecting the level of wholesale price convergence between markets which dampen the incentive for interconnection.

In spite of these new and higher risks, the cap and floor regime remains a generally appropriate vehicle for delivering interconnection, balancing the high degree of certainty investors need with incentives to deliver the best value for consumers. However, adjustments to the cap and floor regime in this higher risk environment are needed.

Q21. What amendments, if any, would be required to the Cap and Floor model given the move from a developer-led to a strategically-led energy system?

On the one hand, risks facing interconnectors are growing due the reasons mentioned in the response to the previous question. On the other hand, a shift toward more centralised, long-term planning will counter much of this level of risk.

Amendments to the future of the cap and floor should, therefore, reflect these two countervailing forces.

The future regime should therefore not simply increase support but differentiate between risks that can be socialised through planning and those that should remain with developers.

The new risk environment means Ofgem will likely have to consider higher and more flexible floors to reflect genuine increases in cost of capital, construction and operational uncertainty. It may also mean a move toward new indexation mechanisms (e.g. linking allowed revenues to input cost indices or supply chain benchmarks) and the introduction of contingent risk-sharing mechanisms, such as reopeners for extreme cost overruns driven by exogenous shocks or even prolonged outages (including due to sabotage). As stated in our answers to other questions, this will need to be accompanied likely by the use of preliminary funding for interconnectors ahead of delivery.

Further risk mitigation is where planning becomes critical. Well-designed, cross-border central planning can mitigate against demand uncertainty, locational risk, and supply chain risk for project identified as essential to the SSEP/CSNP. These projects can benefit from lower cost of capital assumptions, stronger floor protection (quasi-RAB characteristics), and potentially availability-based revenues. Meanwhile, merchant interconnector projects can continue with a more traditional cap and floor process with higher risk exposure accounted for and a higher floor price to reflect this but less protections.

Further, given the increased importance of interconnectors to GB system resilience and security, part of the cap and floor calculation should account for the project's value under stress scenarios, resilience to geopolitical disruptions during operation, and curtailment reduction. This may involve amendments to interconnector treatment within the Capacity market (CM) rather than the cap and floor but perhaps some availability measure could be accounted for within the cap and floor, given the former requires the existence of a connection agreement to be used. This would help reflect explicit remuneration for availability and resilience, not just utilisation.

In line with OTC's work on a cost and revenue sharing framework for hybrid projects described in an answer to a previous question, a tailored cap and floor regime for the GB-portion of a project will be needed that accounts for the diverse revenue streams a project is receiving and what the 'hierarchy' of those streams is for the project's success. This tailored system must consider how project risk is shared across TSOs in line with OTC's ongoing work.

Finally, introducing pre-agreed upon milestone-based adjustments to the cap and floor, rather than project timeline-based adjustments, under various scenarios, in concert with the scenarios being developed under the SSEP, will help mitigate supply chain risk.

Q22. Given the differing risk and cost profiles of different asset types, should different assets be financed using different models? If so, what model would be most suitable for what asset type, and what would be the key elements/parameters of that model?

More novel technology types, like hybrid assets, would benefit from some RAB-like features within the cap and floor like having a much stronger floor and perhaps the use of pre-operation revenue.

We would advocate for an hybrid project pilot window to cover the regulatory gap over the transitional period. This would drive policy changes required to enable cross-border coordination of offshore GB wind. It would be in line with the Hamburg Summit ambitions and provide an opportunity to deliver strong consumer benefits that MPIs can deliver.

More established point-to-point interconnectors, especially those not within the SSEP, can continue to rely on the existing cap and floor regime.

Q23. Do you believe that supply chain issues currently affecting interconnection projects will abate or not in future? If not, what is your assessment of why these issues will endure?

In the near-term, supply chain risks appear like they will likely persist and perhaps worsen, at least until the end of this decade. Beyond then, production slots have a good chance of catching up with the backlog of orders from across the world's major electricity infrastructure firms.

The two major risks that could cause this risk to persist beyond then are:

1. An unexpected, continued rise in electricity demand worldwide, perhaps due to further increases in data centre demand for the use of Artificial Intelligence (AI)
2. Greater disruption and fragmented of the global trade system as global geopolitical trends worsen. Given reliance on Asian markets for many of the needed components for interconnectors, key objectives here must be the reshoring or friendshoring of HVDC production to Europe or its neighbouring region, and the securing of key global trade chokepoints, namely the Malaca Strait and the Suez Canal/Red Sea.

Q24. Given the increased complexity of MPIs, do you believe that further revenue and risk mitigations will be needed for this asset type? Why? And what revenue and risk mitigations should we explore?

For novel interconnector technology types that require anticipatory investment and a large degree of certainty to attract affordable investment, further mitigations will be needed for the time being.

Similar to other European jurisdictions, this could include pre-revenue funding based around the early securing of needed supply chain equipment. This could be modelled off the anticipatory investment funding that was used for the ASTI projects for GB's onshore network as well as some of the anticipatory investment mechanisms in the RIIO-T3 framework.

Q25. As revenue and risk mitigations can transfer costs and risks to consumers before the asset is operational, what mechanisms, if any, should be considered to ensure effective and efficient project delivery?

At the outset, ensuring early project need and coherence with national and wider North Sea spatial plans will help mitigate against consumer risk from pr-operation funding.

Beyond this, pre-revenue funding should only be released progressively against clearly defined delivery milestones, such as the Final Investment Decision (FID, securing of supply chain contracts, start of initial work on the seabed etc. The funding should be clearly defined and linked to addressing an exogenous risk, namely supply chain risk.

Crucially, there should be symmetric risk sharing attached to pre-operation revenue. This means, at the outset, an agreed upon portion of cost overruns should be borne by the developer just as the developer should also benefit from delving milestones under budget. Pre-revenue funding should be penalised due to on-exogenous delays to projects.

To be clear, pre-revenue funding should be for novel interconnector types only, namely hybrid projects, especially those identified as need in the CSNP.

Q26. Given the move from a developer-led to a strategically-led energy system, are current availability and performance incentives still fit for purpose?

Generally speaking, the primary concern regarding spatial planning is the question of capital investment risk, not operational performance. For this reason, the current cap and floor performance incentive remains generally appropriate.

Q27. What availability and performance incentives should be part of the future financing model, and how should they balance the interests of consumers and developers?

Ofgem could consider incentives for availability during periods of system stress as this an increasingly important value interconnectors provide. Admittedly, this may be something better addressed in the CM regime than the cap and floor regime.

Further, given many project risks increasingly sit in the pre-operational phase, rather than operation, this increases the needed for performance incentives within a pre-operational funding system. His should include rewards for on time delivery and penalties for long delays.

Q28. Should different asset types (P2PS, NSIs, MPIs) have different availability and/or performance incentives? If so, what should be the incentives for each asset type?

Hybrid assets will have more complex commercial operations than traditional interconnectors. A relatively straightforward solution from a developer perspective might be to have the existing revenue incentive framework apply to all the hybrid asset's operations across jurisdictions, not just those pertaining to the GB market. This would require agreement between developers and national regulators at the outset.