January 2026

Evolving the OFTO Regime to enable the next wave of offshore wind

Foreword

Over the last two decades, the Offshore Transmission Owner (OFTO) regime has played a key role in making the UK a global leader in offshore wind. Allowing developers to build offshore transmission assets and divest them through a regulated process that has driven timely delivery, reduced delays, and attracted low-cost finance through stable, regulated returns. This approach has accelerated offshore wind deployment, protected consumers, and allowed developers to reinvest into new projects, delivering real economic benefits and progress towards Net zero.

However, the landscape is changing and the OFTO regime faces mounting pressure to adapt to the pace of offshore wind development. Offshore wind projects are increasing in size, complexity, and cost alongside further advancement in technology and asset development. Consequently, the existing regulatory framework requires further development to provide greater certainty. Ofgem has taken steps, such as enabling life extension and promoting coordination, but further evaluation of the regulatory framework is essential.

To address the key challenges for the OFTO regime RenewableUK and Scottish Renewables commissioned this report. There are 13 recommendations highlighted in this report to address the challenges across four priority areas:

1. Cost Assessment
2. Generator Commissioning Clause (GCC)
3. Operations and Maintenance (O&M) incentives
4. End of Tender Revenue Stream (EoTRS) policy

We believe the recommendations in this report will act as enablers for the OFTO regime — ensuring speed and efficiency to achieving net zero targets and keeping costs down for consumers.

The OFTO framework has helped to bring forward long-term private investment, drive cost efficiency, and deliver value to consumers during the early stages of the UK's offshore wind rollout.

However, the energy system is now entering a period of significant change. Offshore wind ambitions continue to grow and the number and size of assets coming to market is increasing. There is therefore a need to modernise the OFTO framework so that it is fit for purpose – specifically, to maintain:

- New capacity – reliant on a smooth, efficient and fair transaction process.
- Projects that are operating – who are dependent on the offshore transmission system to export green electrons
- Capacity nearing the end of its planned operational life.

The time is therefore right for Ofgem to consider the suitability of OFTO regime moving forwards. In developing this report, industry has considered how the framework may need to evolve and sets out a series of recommendations to inform policy development and industry debate. We believe that through considered, strategic amendments to regulation and legislation — focussing on evolution rather than revolution — the OFTO framework will remain fit for purpose.

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RenewableUK

RenewableUK is the voice of the UK's renewable energy industry. Representing close to 500 companies spanning the full supply chain, our members develop, operate and maintain the UK's wind, tidal, storage and flexibility infrastructure. By connecting industry and policy makers, we strengthen the UK's global leadership in renewables, building a secure, affordable and sustainable energy future.

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Executive Summary

The OFTO regime must evolve to support a maturing offshore wind sector

The Offshore Transmission Owner (OFTO) regime has supported Great Britain[1] in establishing itself as a global leader in offshore wind generation over the past two decades. This rapid expansion represents a significant success story that has brought considerable value to the UK economy and progress towards net zero goals. The success has been driven by a regulatory model that enables offshore wind developers to construct the grid assets (and therefore highly incentivised to deliver on-time to avoid loss of revenue) before they are divested through a regulated process to licenced OFTOs. The regime has proven particularly effective at delivering offshore wind farms quickly and attracting low-cost finance into the sector by providing stable, low risk returns to investors through the OFTO's Tender Revenue Stream (TRS). The regime helps protect consumers from delays to transmission infrastructure delivery and enables developers to re-cycle capital from divestment of transmission assets to fund new generation projects.

However, there is broad consensus amongst generators that the OFTO regime faces pressure to keep pace with challenges posed by wider policy changes, assets approaching end-of-life, the increasing size, complexity and cost of offshore wind and transmission projects, and technology changes which change how projects are designed, procured, constructed and operated. Whilst Ofgem has been proactive in evolving the OFTO regime, most notably to enable life extension of existing offshore wind farms, as well as to enable coordinated offshore transmission networks, significant challenges remain in these areas, and others besides. This report emphasises that, if UK offshore wind targets are to be met whilst minimising costs to consumers and achieving net zero by 2050, changes to the regulatory framework are needed to overcome present and emerging challenges.

1 The OFTO regime applies only to Great Britain, which is under the jurisdiction of Ofgem; Northern Ireland has a distinct regulatory framework and has no equivalent to the OFTO regime.

This report finds:

Four aspects of the regime which have not evolved sufficiently or have remaining challenges are:

- Cost Assessment
- Generator Commissioning Clause (GCC)
- Operations and Maintenance (O&M) incentives
- End of Tender Revenue Stream (EoTRS) policy

These aspects have not kept pace with:

- The increased scale and complexity of projects
- Introduction of Contracts for Difference (CfD) auctions
- Assets approaching End of Tender Revenue Stream
- Emergence of floating offshore wind technology
- Coordinated offshore transmission infrastructure

Navigating this report

Section 1 of this report examines the evolution of the OFTO regime and how it has responded, and continues to respond, to changes in the sector.

This report then sets forth recommendations focused in two areas:

Section 2: Recommendations for the OFTO regime addresses challenges within the existing OFTO regime.

Section 3: Recommendations for the future OFTO regime addresses upcoming challenges facing the OFTO regime

The **appendices** include international perspectives on life extension of offshore wind warms and transmission assets (Appendix 1) , and EU perspectives and examples of generator ownership of transmission assets under unbundling arrangements (Appendix 2).

Key recommendations for the existing OFTO regime

Several aspects of the OFTO regime require reform to address challenges which are currently impacting generators and, consequently, consumers through higher electricity prices.

Key recommendations to address barriers within the existing OFTO regime include:

	Recommendation
1	Ofgem should transform the Cost Assessment process from an adversarial to a confirmatory process, recognising that Contracts for Difference (CfD) auctions already incentivise economic and efficient transmission asset costs, thereby preventing unnecessary financial risk being passed to consumers through risk premiums in CfD strike prices.
2	The Cost Assessment guidance should be simplified, and legitimate financing costs allowed within the FTV, to reduce uncertainty and prevent unnecessary risk premiums in CfD prices.
3	Ofgem should publish clearer guidance on the decision-making process for critical and strategic spares within the existing Cost Assessment process, to remove disincentives on developers procuring spares which have long lead times or are critical for resilience.
4	Ofgem and DESNZ should continue to explore the appropriate measures and protections to limit the asymmetric negotiating power of OFTOs within the Generator Commissioning Clause (GCC) period.
5	Ofgem should introduce an Operations and Maintenance (O&M) scorecard within the existing availability incentive to address situations where the current availability incentive may be perceived to have limitations, for example for auxiliary equipment maintenance, and once the availability revenue loss floor is reached.
6	Ofgem should ensure generators retain the option to participate in providing O&M services to OFTOs, recognising that this mitigates misaligned incentives given that OFTO penalties are capped significantly lower than the losses a generator could incur from a transmission outage and that this arrangement is beneficial for consumers.
7	Ofgem should publish more detailed contingency plans for a situation where a generator wishes to extend but the incumbent OFTO wishes to divest or decommission the assets, or a situation where the ERS cost is too high. This should include greater clarity on the re-tender process and asset transfer value, re-tender timelines and alignment with decommissioning, and the compatibility of the OFTO of Last Resort and property transfer scheme processes with EoTRS timelines.
8	DESNZ and Ofgem should allow a licence exemption for generator ownership of radial transmission assets as a backstop to failed ERS re-tenders, which would restore meaningful competition to ERS negotiations and ensure that pricing more accurately reflects efficient costs and appropriate risk allocation.
9	To enable life extension of older assets where the costs of an ERS may be disproportionate to the remaining benefits, generator ownership of transmission assets should be allowed for a period of five years or less.
10	Ofgem should further evolve End of Tender Revenue Stream (EoTRS) policy to provide generators with greater certainty on the business case for life extension by defining an Extension Revenue Stream (ERS) calculation mechanism, providing guidance on asset transfer value, and sharing the ERS cost forecast received from OFTOs at year T-5 and T-4 with generators to enable timely decision-making on life extension versus decommissioning.
11	Ofgem should continue to gather evidence to support a decision on extending the 25-year TRS period, and publish an indicative timeline for a decision.

Key recommendations for the future OFTO regime

Generators welcome Ofgem's continued willingness to evolve the OFTO regime, including the recent call for input on OFTO Build, and look forward to further consultations and policy development to support the further development of the UK's offshore wind sector in 2026. Upcoming challenges that the OFTO regime will face include accommodating emerging technologies and the introduction of new approaches to network planning.

The key recommendations related to upcoming challenges are:

	Recommendation
12	Ofgem should adapt the OFTO transaction process to provide greater flexibility for floating offshore wind projects, recognising the extended and phased nature of floating wind deployment and commissioning, which does not align with conventional Generator Commissioning Clause timelines or OFTO preferences for transmission assets tested at full capacity before transaction.
13	Ofgem should develop and implement a workable OFTO Build policy, including Ofgem's proposals for centralised OFTO Build tenders, which would address many challenges by transferring responsibility for financing, design, construction, and operation to OFTOs, thereby eliminating Generator Commissioning Clause pressures and Cost Assessment uncertainty for developers.

The OFTO regime has been successful in enabling rapid scale up of offshore wind capacity, but it is not of fundamental importance to the future of the GB offshore wind sector. Other nations have successfully deployed offshore wind through different approaches, as outlined in the appendices of this report. Ultimately the success of the sector is determined by attracting generators to design and build the wind farms and transmission assets - without a policy environment which makes it attractive for generators to invest there can be no OFTO regime. Therefore, for the benefit of generators, OFTOs, UK plc, and consumers, it is critical that the OFTO regime does not become a barrier to investment in offshore wind generation, and GB should not be afraid to explore alternative models where they could offer greater benefits to consumers.

The Evolution of the OFTO Regime

1.

1.1 The OFTO regime has been successful in delivering offshore wind projects quickly

In the past two decades the United Kingdom has successfully deployed more than 16 GW of operational offshore wind capacity[2], making it the largest offshore wind market in Europe and the second largest globally after China. This rapid expansion represents a significant success story that has brought considerable value to the UK economy and progress towards net zero goals. The OFTO regime has been a feature of that success, incentivising developers to deliver projects on time, whilst reducing financing costs by divesting transmission assets to OFTOs which are able to attract low-cost capital by offering stable and predictable returns, in the process enabling developers to re-cycle capital to fund new generation projects.

1.2 The OFTO regime faces pressure to keep pace with wider policy changes, the increased scale of projects, changes in technology, and assets approaching end of life

The pace and scale of change in the offshore wind sector places pressure on the OFTO regime to evolve with the maturing offshore wind industry. Since the OFTO regime was introduced the policy environment has changed significantly, altering the economic incentives and competitive dynamics of project development. At the same time, technological advancement has seen projects scale in capacity by a factor of 10 and move further offshore, multiplying both the complexity of transmission infrastructure and the financial stakes involved. As the regime enters its second decade, the first OFTO projects are approaching the end of their Tender Revenue Streams and are faced with uncertainty regarding the viability of life extension. In specific areas of the regime there exists a growing misalignment between the assumptions, policies, and processes in place (often since the beginning of the regime), and the contemporary realities of the offshore wind industry. This raises questions about the fitness for purpose of certain aspects of the regime in supporting the next phase of renewable energy expansion whilst protecting consumer interests.

2 https://www.renewableuk.com/energypulse/ukwed/

1.3 Four aspects of the regime which have not evolved sufficiently or where challenges remain are the Cost Assessment process, the Generator Commissioning Clause, End of Tender Revenue Stream policy, and Operation & Maintenance incentives

Ofgem has been proactive in evolving the OFTO regime in several areas, most notably End of Tender Revenue Stream policy to enable the life extension of existing offshore wind farms and, enabling coordinated offshore transmission networks[3]. However, despite the progress in these areas some challenges remain in implementing these policies, and in other areas there has been less progress on policy development. The following section introduces remaining challenges related to the Cost Assessment process, the Generator Commissioning Clause, Operations and Maintenance incentives, and End of Tender Revenue Stream policy.

1.3.1 Cost Assessment

The Cost Assessment process remains important, but the use of project cost benchmarking to assess economic and efficient costs is no longer fit for purpose given the scale of offshore wind projects and the duplication of incentives introduced through the Contracts for Difference (CfD) allocation rounds.

Generators build the transmission assets and pay for approximately 80% of the development costs of the OFTO assets through Transmission Network Use of System (TNUoS) charges, therefore they are inherently incentivised to minimise the cost of the transmission asset in order to achieve a competitive bid in the CfD allocation rounds.

The OFTO regime's Cost Assessment process assesses whether the costs incurred in developing, constructing, and divesting the transmission assets are economic and efficient, such as offshore substation, onshore and submarine cables, onshore substation, and transaction costs. This process has been in place since 2009, pre-dating the competitive CfD allocation rounds by 6 years.

The Cost Assessment process uses several methods to achieve its objectives, including:

- Correct cost allocation - ensuring costs are correctly allocated between transmission and generation assets to prevent cross-subsidy between the two categories.
- Procurement and contract management audit. - reviewing developers' procurement processes and contract management approaches for main expenditure items to confirm that economic and efficient outcomes were delivered.
- Accounting analysis to confirm that contracts presented at earlier stages have been performed and to reconcile stated contract costs with actual payments.
- Cost benchmarking which compares a developer's submitted project costs against historical costs from previous offshore transmission projects to determine whether the expenditure is economic and efficient, with costs exceeding these historical comparisons subject to potential disallowance.

Cost allocation and benchmarking are used to systematically evaluate developers' submitted costs at both Indicative Transfer Value (ITV) and Final Transfer Value (FTV) stages, to ensure that capital expenditure and other costs have been incurred economically and efficiently.

Cost allocation, which remains highly relevant for the enduring OFTO regime, is the methodology by which developers must correctly apportion costs between different cost categories as set out in Ofgem's Cost Assessment Template[4], and between transmission assets and generation assets. This ensures costs are attributed to each category and asset correctly without cross-subsidy between transmission and generation elements. Ensuring that costs are correctly allocated is crucial to Ofgem's remit and this part of the Cost Assessment process should remain in place for as long as the regime continues to socialise part of the transmission asset costs.

Cost benchmarking is a comparative analysis tool where Ofgem examines how the direct costs submitted by developers compare with industry averages derived from previous projects. Ofgem states that this analysis is used to guide decisions on which cost areas warrant further investigation rather than as an absolute determinant of allowable costs. However, in practice developers' experience is that the benchmarking data is the baseline for Ofgem's view of whether costs are economic and efficient. Where costs are deemed to be not economic based on differences in the benchmark or differences at the line item, developers are required to justify the reason for difference or face partial or full disallowance of the cost difference.

3 As the first OFTO projects awarded in 2009 approach the end of their regulated Tender Revenue Stream (TRS) Ofgem has updated the OFTO regime with a framework for life extension through its January 2024 End of Tender Revenue Stream decision, June and July 2023 licence modifications enabling cost recovery for Health Reviews and Investment Works, and November 2024 Guidance for Health Reviews. Collectively these policies aim to maximise the useful life of generation and transmission assets and protect consumers from premature replacement of existing capacity with new capacity subsidised by CfDs.

Meanwhile, to reduce barriers to coordinated offshore grid development and support the UK's 60GW offshore wind target by 2030, Ofgem's October 2022 Anticipatory Investment decision introduced risk-sharing mechanisms and early-stage assessment processes for coordinated projects.

4 https://www.ofgem.gov.uk/sites/default/files/2022-03/Offshore%20Transmission%20Guidance%20for%20Cost%20Assessment%202022.pdf

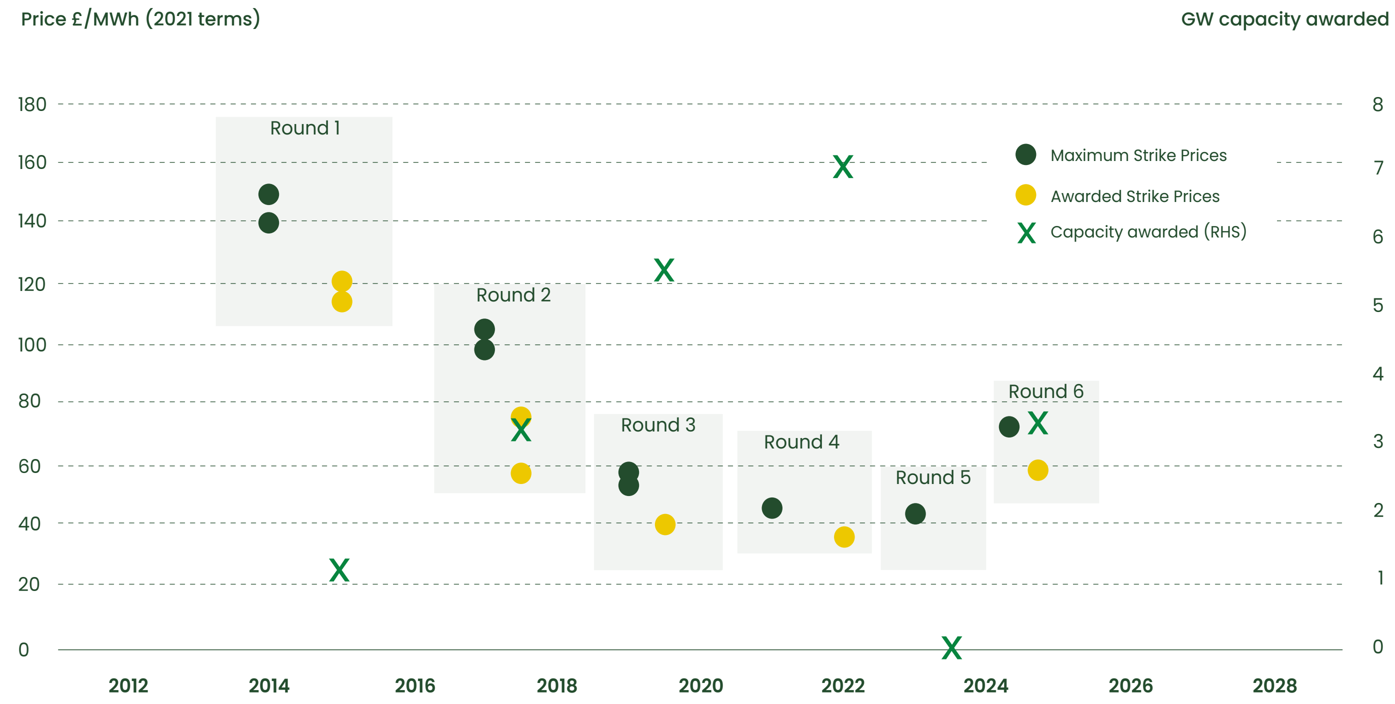


Figure 1 — CfD strike prices by Tender Round
https://ore.catapult.org.uk/resource-hub/blog/allocation-round-6-results-and-analysis

The Contracts for Difference (CfD) scheme introduced in 2015 transformed how offshore wind projects are procured and priced in the UK, rendering cost benchmarking not only obsolete, but counterproductive to Ofgem's objectives. Whilst Renewable Energy Certificates (ROCs) provided administratively awarded subsidies CfDs introduce competition through competitive bids between generators, with the lowest strike prices securing CfDs. The competitive allocation round incentivises generators to reduce the cost of both generation and transmission assets which therefore renders cost benchmarking obsolete. Coupled with technology improvements, the CfD mechanism has enabled cost reductions in offshore wind, with strike prices falling by approximately 50% since 2015 (see Figure 1).

The cost of transmission assets has increased by an order of magnitude since the OFTO regime was established, with proportionately greater impacts on developers resulting from Cost disallowance

The developer takes on significant financial risk in constructing the transmission asset, which is typically 25-50% of the total project value. The increase in average OFTO asset values from £127m in Tender Round 1 (TR1) to £1.3 billion in TR8, TR9, and TR12 has resulted in proportionately higher construction risks and financing challenges for developers. As project sizes have grown and the GB and international market for offshore wind has expanded, developers are increasingly exposed to supply chain disruptions and vessel availability constraints. The technical challenges of installing increasingly sophisticated infrastructure, such as HVDC converter stations and subsea cable systems, in harsh marine environments has also increased construction risk. To illustrate the growing financial implications of cost disallowance, based on an average disallowance of 7%[5] of the developer requested final transfer value (FTV) and applying this disallowance to average OFTO final transfer values in TR1 (**Figure 2**) would have resulted in £9.6m of costs being disallowed, but in TR8, TR9, or TR12 which had FTVs of £1.3 billion, this would grow to £98 million in costs being disallowed[6].

It is not only the scale of disallowance, but also the degree of uncertainty which is of consequence. Uncertainty primarily arises from insufficient clarity in Ofgem's Cost Assessment guidance, and the use of precedent to guide some Cost Assessment decisions — which in some cases has not been consistently applied.

Under these circumstances developers rationally evaluate that they should expect to face significant disallowed costs and look to protect themselves from this risk by making allowances in their revenue assumptions, whether through pricing risk into CfD bids, or assumptions on breakeven

5 Since TR5 the average disallowed cost between developer requested FTV and FTV is 6.7%, with a range from 2.2% to 14.3%; Source: Ofgem Cost Assessment reports.

6 Actual disallowed cost % from requested FTV to FTV in TR8 and TR9 was 4.2% and 7.1% respectively. At time of writing this report the Sofia project in OFTO TR12 is still in development.

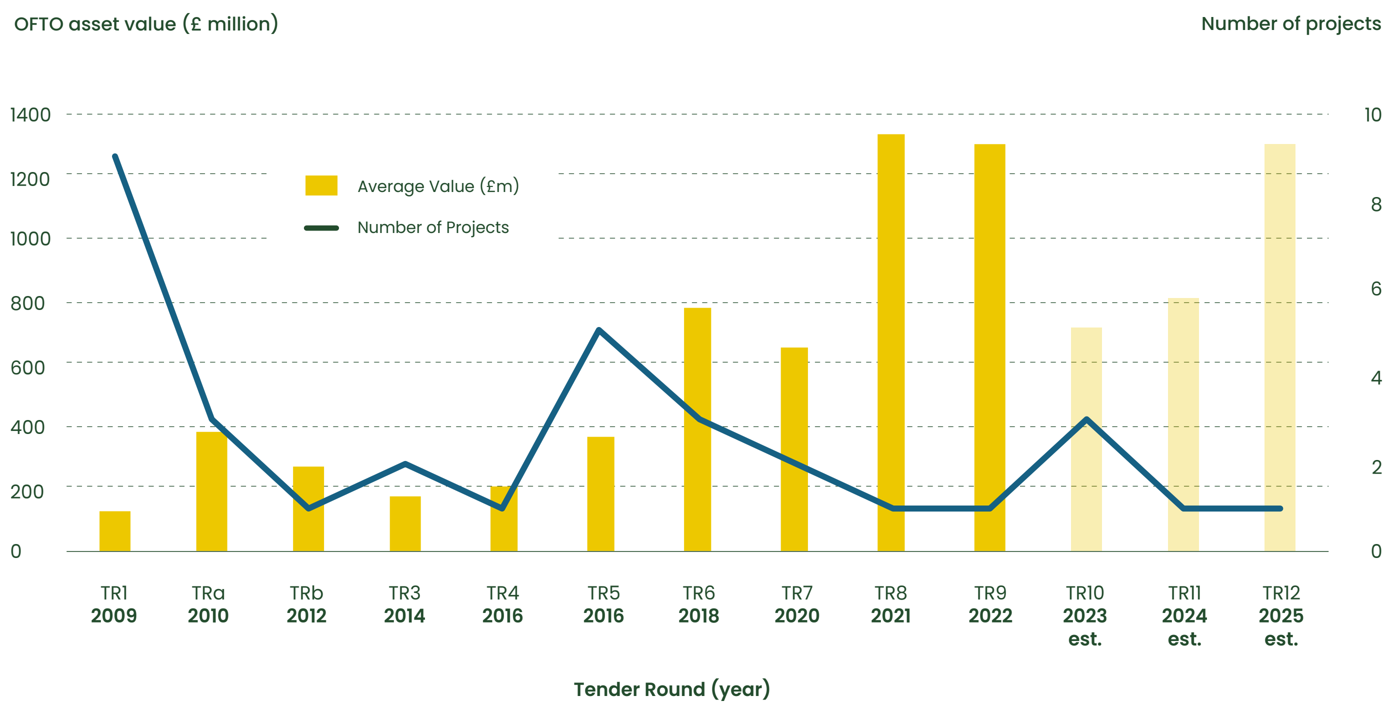


Figure 2 — Average OFTO asset value by tender round. Source: **Ofgem**

PPA or wholesale power prices. Building risk into business model assumptions is common practice in all commercial enterprises, indeed the OFTO regime itself embraces this fact by providing OFTOs with certainty on risk exposure to reduce risk premiums and attract lower cost capital. Therefore, when developers respond to risk exposure by building protections into their business models to ensure long-term project and business viability, it is in keeping with accepted practice within both within the OFTO regime and the commercial sector more generally.

Thus disallowed costs do not necessarily provide any benefit to consumers, and may even result in higher cost to consumers than in a scenario where there was no routine cost disallowance; the Cost Assessment process aims to protect consumers from uneconomic and inefficient costs arising from development of transmission assets, but may inadvertently pass cost risk back to consumers through higher electricity prices.

1.3.2 Generator Commissioning Clause

The Generator Commissioning Clause (GCC) is a regulatory requirement that imposes a time-limited window during which developers must complete the transfer of offshore transmission assets to the OFTO, with criminal liability if developers exceed this deadline. The process for extending the GCC is currently very challenging since developers must obtain a Section 5 exemption[7], which requires secondary legislation to pass through Parliament, as well as sign-off from the Secretary of State.

DESNZ has extended the GCC duration from 18 to 27 months through reforms implemented in the Planning and Infrastructure Bill in which became law in December 2025. This decision reflects the increase in size and complexity of offshore wind projects since the GCC's introduction in 2013, when wind farms and transmission assets were smaller and connections were generally radial.

Irrespective of the duration, the current GCC framework provides OFTOs with asymmetric negotiating power during the transaction process because whilst developers face criminal liability if the GCC deadline is missed, OFTOs face no such risk. There have been reported instances of OFTOs leveraging this negotiating power to demand indemnities and other one-sided commercial terms which developers are compelled to accept in order to close the transaction on time, and avoid breaking the law. Developers acknowledge that Ofgem's recent consultations[8] on bidder incentive mechanisms are attempting to address this imbalance, however there is broad view amongst developers that given the underlying structural causes of the imbalance, it is not appropriate for OFTOs to be rewarded for meeting minimum expectations on good faith negotiations through an incentive paid for by developers and/or consumers.

7 https://assets.publishing.service.gov.uk/media/64ca699a6ae44e001311b40e/offshore-transmission-licence-exemptions-august-2023-guidance.pdf

8 https://www.ofgem.gov.uk/sites/default/files/2025-07/OFTO-Further-Evolution-of-a-Mature-Asset-Class.pdf

1.3.3 Operations and Maintenance (O&M) Incentives

The OFTO regime incorporates several O&M incentives, principally through licence conditions requiring OFTOs to operate and maintain transmission assets in line with good industry practice[9] and the availability incentive mechanism, which rewards OFTOs by up to 5% of annual revenue for exceeding the 98% availability target and penalises them when falling below it by up to 50% of annual revenue spread over 5 years, effectively capping the penalty at 10% of annual revenue. This is intended to encourage behaviour that maximises asset availability through effective Operations and Maintenance activities.

However, there two situations where the incentive might break down:

1. The availability incentive does not incentivise maintenance of auxiliary equipment and structures which do not directly affect the availability target, such as lifting gear and other non-critical equipment. An OFTO looking to make efficiency savings without impacting the availability incentive could de-prioritise maintenance spending (or opt not to expedite repairs at increased cost) for equipment that does not immediately impact transmission availability.

2. The 90% annual revenue loss floor can result in a perverse incentive where an OFTO which has already reached the floor may opt for the least expensive route to restoring transmission availability, even if that results in a longer outage. This is because once the penalty floor is reached, the OFTO's financial incentive switches from restoring availability as quickly as possible to minimising the cost of the repair. Therefore, in such a situation the urgency of restoring transmission availability is undermined, potentially resulting in longer outages that adversely affect connected generators whilst having minimal additional financial consequence for the OFTO.

1.3.4 End of Tender Revenue Stream

The first OFTO projects are now approaching the end of their Tender Revenue Stream (TRS) and decisions must now be made on life extension vs. decommissioning.

Tender Round One (TR1) projects, which were licenced between March 2011 and November 2014 are approaching the end of their revenue streams. Barrow Offshore Wind Farm OFTO is set to be the earliest OFTO to reach the end of its regulatory revenue period in 2030[10], having agreed a shorter 18.5 year TRS than the other TR1 projects. Ofgem has been developing an End of Tender Revenue Stream (EoTRS) policy framework to enable extensions for assets that remain economically viable, thereby avoiding premature decommissioning and ensuring continued value for consumers.

Coordinating an extension between generators and OFTOs involves balancing the expected offshore wind farm revenue during the extension period against the cost of investments needed for life extension and O&M costs of both the offshore wind farm and the transmission asset during the extension. The condition of transmission equipment and the value of the extension revenue stream which the OFTO will receive (which is paid by the generator through TNUoS charges), are key to informing generator decision-making on life extension. For generators, the business case for extension is particularly challenging because wind farms will have lost their original subsidies through Renewables Obligation Certificates (ROC) or Contracts for Difference (CfD), leaving them entirely dependent on volatile wholesale market prices during the extension period.

Should the business case for life extension prove to be unviable or too uncertain, generators expect that at least 6 years is needed to prepare for decommissioning for the initial projects, however this could reduce over time as generators become more familiar with the process. Consequently, generators need indicative information on the ERS value by T-5 at the latest.

Based on currently available End of Tender Revenue Stream policy announcements generators remain unclear on what information will be provided at T-5 and how useful this will be to provide a degree of certainty to commit to life extension or decommissioning. If generators do not have sufficient certainty early enough in the process, then life extension and decommissioning planning will need to be conducted in parallel — which is costly and inefficient since decommissioning planning would likely need to be repeated in the event of a longer life extension.

Should generators choose to decommission offshore wind farms at the end of TRS instead of life extension there is the potential for large volumes of capacity to come offline earlier than is technically necessary, resulting in increased cost to consumers and directly undermining the UK's ability to meet its net zero commitments.

9 Amended Standard Condition E12–J4, Part A.3 https://www.ofgem.gov.uk/sites/default/files/2024-02/Generic%20OFTO%20Licence%20TR11_V1.pdf

10 https://www.ofgem.gov.uk/sites/default/files/2022-06/2nd_Consultation_EoTRS_Final.pdf ; https://www.amberinfrastructure.com/sectors/case-studies/barrow-ofto

1.4 These challenges increase the risk of investing and developing offshore wind projects in the UK, therefore further changes to the OFTO regime are needed to better meet Ofgem and Government objectives

Ofgem's principal objective is to protect the interests of existing and future consumers, this includes minimising cost to consumers and achieving net zero by 2050[11]. Ofgem is also subject to a Growth Duty, applied to specified regulatory functions in the UK, which means it must have regard for the desirability of promoting economic growth[12] in its decision-making. Complimentary to Ofgem's objectives, the UK Government's Invest 2035 industrial strategy aims to "attract internationally mobile investment in strategic sectors and spur domestic businesses to boost their investment and scale up their growth". Clean energy industries are amongst the key sectors which are the focus of the strategy.

The OFTO regime has contributed to the rapid scale up of offshore wind capacity in GB, but it is not of fundamental importance to the future of the offshore wind sector — at least where radial transmission is concerned. Generators design and build the wind farms and transmission assets, and are capable of operating both, and in other nations, Transmission System Operators (TSOs) design, build and operate offshore transmission infrastructure. Without a policy environment which makes it attractive for generators to invest there can be no OFTO regime. Therefore, for the benefit of generators, OFTOs, UK plc, and consumers, it is critical that the OFTO regime does not become a barrier to investment in offshore wind generation.

11 https://www.ofgem.gov.uk/guidance/our-powers-and-duties
12 https://www.gov.uk/government/publications/growth-duty

Recommendations for the OFTO Regime

This section sets out recommendations to reform the OFTO regime to better align with Government objectives of achieving net zero whilst protecting consumers. An OFTO Build model exists within the current OFTO regulatory framework, however, this option has never been used. The recommendations presented in this section apply to the Generator-build model, which remains the primary delivery mechanism for offshore transmission infrastructure in GB. Each recommendation identifies the underlying problem, examines the impact on generators and consumers, and proposes practical solutions to ensure the regime continues to deliver value for money whilst supporting the rapid expansion of offshore wind capacity required to meet the UK's decarbonisation targets.

2.

Cost Assessment

2.1 Recommendation 1:

The Cost Assessment process should change from an adversarial to a confirmatory process, recognising developers are incentivised to reduce transmission costs which also reduces the cost to the consumer.

The Cost Assessment process was established as part of the regulatory framework for offshore electricity transmission in 2009. The process was originally much less adversarial. It was designed at a time when offshore wind farms primarily utilised the Renewables Obligation Certificates as their route to market, with the Cost Assessment providing a check and balance for ensuring developer expenditure on transmission infrastructure and ensuring this represented value for money for consumers who pay the smaller proportion of transmission costs. The offshore wind industry and associated offshore transmission is now much more efficient as the market has incentivised lean construction and operation, as evidenced by strike price reductions. Some of the methods within the Cost Assessment process remain necessary to protect consumers; for instance, Ofgem should continue to assess whether developers correctly allocate costs between generation and transmission assets, and whether they allocate costs correctly to different asset categories which may have different degrees of socialised costs.

2.1.1 The Cost Assessment process is now disproportionate to the value delivered, with increasing intervention adding uncertainty and risk which damages the sector.

Cost benchmarking is not needed due to the incentive of the CfD
Cost benchmarking for efficient and economic costs is no longer required because the introduction competitive CfD capacity auctions already incentivises developers to minimise the cost of the transmission asset (see Section 1.3.1: Cost Assessment).

The risk which generators price into CfD bids has increased due to the difficulty in predicting cost disallowance decisions, we identified five underlying reasons which have contributed to this:

1. There is insufficient transparency of benchmarking datasets and calculations which makes it difficult to satisfy Ofgem's requirement to explain variance to these benchmarks
During Cost Assessment Ofgem asks developers to explain cost differences between their project and benchmarked projects, however developers argue that it is often impossible to explain cost differences without understanding what they are being benchmarked against, and therefore greater transparency of Ofgem's

benchmarking data and calculations is needed. Ofgem argues that it is unable to provide access to benchmarking datasets to protect the confidentiality of developers data, however Ofgem could overcome confidentiality concerns by pursuing middle-ground options such as sharing anonymised or aggregated data, fully publishing benchmarking methodologies, or engaging trusted third-party consultants under agreed confidentiality terms to review benchmarking methods and datasets.

2. Benchmarking practices fail to recognise market forces which can result in unpredictable cost disallowance
Benchmarking against previous projects is inherently backward-looking and so it fails to adequately reflect contemporary market forces such as inflation, supply chain constraints, or market volatility.

Ofgem applies inflation adjustments to historical project data, uplifting costs from all projects since Tender Round 1 using the Consumer Prices Index, with additional uplift factors applied for specific commodities such as metals and fuels. However, Ofgem acknowledges that its benchmarking model may not capture all inflation factors and commits to accounting for project-specific factors when assessing costs.

This creates substantial uncertainty for developers, who must price in the risk of cost disallowance. For example, contracts for high-voltage direct current (HVDC) assets are often placed up to ten years ahead of the Cost Assessment process leaving developers exposed to significant uncertainty about which costs will ultimately be recoverable. This results in generators pricing the risk of disallowance into their CfD bids.

Due to the limited historical data available for HVDC projects, Ofgem employs a broader dataset for benchmarking purposes which encompasses transmission links to wind farms, interconnector projects, and onshore reinforcement projects. Developers have expressed concerns with this approach, arguing that these project types are sufficiently different that benchmarks derived from comparisons between them lack validity.

Nevertheless, the more pressing challenge with HVDC benchmarking relates to the varied and rapidly evolving technology landscape, significant price variations depending on the vendor and technology specification, and supply chain constraints which have resulted in significant price increases in recent years. These factors create large cost differences between projects and therefore pose serious challenges to the use of benchmarking approaches. Ofgem has recognised this in the Eastern Green Link 1 Accelerated Strategic Transmission Investment (ASTI) Project Assessment:

> **We noted that Ofgem's and the TOs' current direct cost benchmarks no longer reflect current contract rates. Innovation and changing market conditions have led costs to increase significantly over the past years, making benchmarks based on historic data mostly obsolete."**

Ofgem, Eastern Greenlink 1 Project Assessment document, November 2024[13]

The inconsistency of Ofgem's ASTI Project Assessment process concluding that Ofgem's HVDC benchmarks are unsuitable for onshore reinforcement projects, whilst the offshore regime uses the same data to benchmark OWF projects indicates that a change of approach is also needed in the offshore regime.

Another example of market forces significantly impacting project costs is access to specialist installation vessels which are in limited global supply. Market pressures for vessel access are difficult to accurately capture in historical benchmarks, especially when average costs are used as a benchmark.

3. There is evidence of inconsistency in Cost Assessment decisions between projects which makes it difficult to predict future decisions
Developers have highlighted a lack of consistency in Cost Assessment decisions as adding to uncertainty and risk. Examples include a spare transformer being permitted on one project and then disallowed on the following project. Similarly, with offshore cable spares, Ofgem accepted the industry-standard practice of holding cable lengths equivalent to the longest section between joints on one project but then refused to accept the same approach on a later project from the same developer. This lack of consistency means that developers cannot rely on previous decisions or established industry practices when planning projects, as Ofgem may reach different conclusions on similar technical matters across different projects. The inconsistency extends to commissioning timelines, where deductions have been made based on assumptions about "efficient" timeframes without clear justification for how these benchmarks were determined.

13 https://www.ofgem.gov.uk/sites/default/files/2024-11/EGL1%20Project%20Assessment%20Decision%20Final.pdf

4. New Cost Assessment guidelines were introduced without prior consultation, creating uncertainty around the rules which will apply to future projects, where procurement may have already commenced for long lead-time equipment

New policies introduced in the 2022 Guidance[14] were implemented without prior consultation, leading to delays and disputes during assessments. Developers would like to work with Ofgem to develop policies which will improve the efficiency and fairness of the Cost Assessment process, saving time and money for all parties, including consumers. By introducing guidance changes without industry input, Ofgem undermined Developer's confidence in the predictability of the process and their ability to accurately forecast project costs during the development phase. Developers welcome that Ofgem have signalled that updated Cost Assessment guidance is being developed, however Ofgem should formally consult with industry to ensure that Ofgem have the required information to enable the development of clear and comprehensive guidance.

5. An under-developed governance framework surrounding Cost Assessment undermines confidence in the process

The governance framework surrounding Cost Assessment does not adequately reflect the significant financial impacts resulting from the process, which can lead to tens of millions of pounds of additional costs for developers. The benchmarking process lacks transparency and accountability and there is no viable[15] formal escalation mechanism available should developers disagree with the outcome of the process. There is a widespread view amongst developers that the guidance, processes, and governance framework surrounding Cost Assessment must be significantly strengthened to ensure a level playing field for all developers.

2.1.2 The uncertainty and risk created by Cost Assessment is likely to be passed to consumers through CfD strike prices. Assuming a conservative 5% cost disallowance is priced in, this would have built in £101m in additional costs to consumers over the previous three tender rounds.

Some developers feel forced to price risk of cost disallowance into their business model assumptions, including CfD bids, therefore even if minimal costs are disallowed consumers will bear additional costs

Whether developers price risk of cost disallowance into CfD bids or other business model assumptions depends on many factors, including routes to market, bidding strategies, and ultimately the risk appetite of the developer. It should be noted that disallowed costs will reduce the TNUoS paid by generators, which does result in some savings over the lifetime of the transmission licence, however the unrecovered cost is most significant in the early years of the project, and this cost must be financed. For the purpose of this analysis we have assumed that risk averse developers price in the risk of 5% disallowance of InTV into CfD bids[16]. Using the transmission asset values in TR7, TR8 and TR9 as an example, and accounting for the benefit to consumers from disallowed costs, this would still result in additional costs to consumers totalling £101m over the three tender rounds.

14 https://www.ofgem.gov.uk/guidance/offshore-transmission-guidance-cost-assessment-2022

15 A judicial review would significantly increase the risk of breaching the GCC deadline

16 This assumption is broadly reflective of a range of different figures identified during the research of this report.

17 https://www.ofgem.gov.uk/decision/offshore-transmission-cost-assessment-seagreen-transmission-assets; https://www.ofgem.gov.uk/decision/offshore-transmission-cost-assessment-triton-knoll-transmission-assets; https://www.ofgem.gov.uk/publications/offshore-transmission-draft-cost-assessment-triton-knoll-east-transmission-assets

Figure 3 — Additional cost to consumer from cost disallowance risk priced into CfD. Data sources[17]

Project	Indicative Transfer Value (InTV)	Developer Final Transfer Value (FTV) Submission	FTV	Cost Disallowed by Ofgem	% Disallowed	Socialised Cost Saving*	Assumed Cost Assessment risk built into business model **	Potential additional cost passed to consumer ***
Triton Knoll (TR7)	£612.5m	£585.9m	£572.7m	£13.1m	2.20%	£2.6m	£30.6m	£28.0m
Hornsea Two (TR8)	£1,212.5m	£1,191.8m	£1,141.2m	£50.5m	4.20%	£10.1m	£60.6m	£50.5m
Seagreen (TR9)	£633.3m	£668.6m	£621.2m	£47.4m	7.10%	£9.5m	£31.7m	£22.2m
Total				**£111.0m**		**£22.2m**	**£122.9m**	**£100.7m**
						* Assumed 20% of asset costs socialised	** Assuming 5% of InTV value	*** Cost priced into CfD minus disallowed cost

In addition, the Cost Assessment process itself is resource intensive

Based on interviews to support the development of this paper, it is estimated that developer resources required to deliver the Cost Assessment process is £450,000 based on 18 months at 3 FTE[18]. Ofgem report that the Cost Assessment process costs in the region of £200,000 per project including direct staff costs, overheads, and external consultant fees. These costs are ultimately passed to consumers through electricity prices.

2.1.3 Cost Assessment should move to a confirmatory process to provide more certainty for developers and reduce costs being passed to consumers through electricity prices.

Replacing cost benchmarking with a confirmatory assessment approach, similar to the Accelerated Strategic Transmission Investment (ASTI) and Anticipatory Investment (AI) frameworks could streamline the Cost Assessment process whilst maintaining robust consumer protection through continued scrutiny of cost allocation, procurement processes, and material cost movements.

A confirmatory assessment approach to Cost Assessment for offshore transmission continue to focus on ensuring:

1. That the developer procurement process delivered competitive outcomes, by retaining the existing procurement audit of selected contracts which Ofgem conducts as part of the Cost Assessment.
2. That costs are correctly allocated between generation and transmission assets.

However, it would remove detailed cost benchmarking for economic and efficient costs and replace it with a similar confirmatory approach to assessing economic and efficient costs utilised in ASTI projects for onshore transmission, and the Anticipatory Investment mechanism for offshore transmission.

Protection of consumers in the ASTI regime:

In the ASTI regime ex-ante project allowances are established and the Transmission Owner (TO) can request re-openers as the project develops. Pre-construction and early construction funding is released during the project development stage, with a detailed assessment of the forecast project cost taking place at the "Project Assessment" stage, which is requested by the TO any time after planning approval is granted (**Figure 4**).

If a company spends less than its allowed totex upon delivery of the project, it can keep a portion of the savings, while the rest is passed on to consumers. Conversely, if a company overspends, it bears a portion of the additional costs[20]. This mechanism is the Totex Incentive Mechanism (TIM). The share of over or underspend borne by the TO is symmetrical to the upside and the downside, and the value is unique for each TO, being set in their respective licences as the Totex Incentive Strength. In RIIO ET2 the Totex Incentive Strength was between 33-49%, whilst in RIIO ET3 Ofgem proposes to introduce a stepped TIM where the share of under/overspend allocated to the TO decreases as the magnitude of under/overspend increases[21].

Under the ASTI regime if costs deviate by more than ±5% between the Project Assessment stage and project delivery TO's can request a Cost And Output Adjusting Event (ASTI COAE)[22] for an "event that is outside of the TOs' reasonable control, and which they could not have economically and efficiently planned a contingency for, and which has a

18 Assuming total employee costs (salary, pension, national insurance etc.) of £100,000 per annum

19 https://www.ofgem.gov.uk/sites/default/files/2022-12/ASTI%20decision%20doc%20-%20Final_Published.pdf

20 https://www.ofgem.gov.uk/sites/default/files/2025-04/RIIO-2%20Electricity%20Transmission%20Annual%20Report%202023%20to%202024%20-%20appendix.pdf

21 https://www.ofgem.gov.uk/sites/default/files/2025-06/Draft-Determinations-Electricity-Transmission.pdf

22 https://www.ofgem.gov.uk/sites/default/files/2023-08/Accelerated%20Strategic%20Transmission%20Investment%20Guidance%20And%20Submission%20Requirements%20Document.pdf

Figure 4 — ASTI funding and approval process[19]

	Funding	Assessment	Output	Re-opener submission window
Pre-construction	2.5%	None	Submit planning application	Any time
Early construction	Up to 20%	Light-touch assessment of reasonableness of proposed activities. No cost assessment, which will be undertaken on a full project (excluding pre-construction) at the next stage	None	2023, 2024, Ofgem-triggered re-opener
Full project allowance	100%	Full project and cost assessment	Deliver project	After planning application submitted

material impact on the scope or cost of an ASTI Output". If granted, the baseline totex allowance is amended by the requested amount, so that the TO does not bear any additional cost above the 5% threshold. If granted, the baseline totex allowance is amended by the requested amount, so that the TO does not bear any additional cost above the 5% threshold.

Additionally, Ofgem has decided to provide a new mechanism to allow for recovery of costs which were identified as uncertain at the time of the Project Assessment, but which could not be effectively estimated[23], this is necessary since there is no "event" which triggers these additional costs so they cannot be reclaimed using the COAE.

Protecting consumers in the Anticipatory Investment (AI) framework:
The Anticipatory Investment (AI) framework utilises a cost variance threshold in its Early-Stage Assessment (ESA) process which allows cost increases of up to 10% above or below the initially agreed amount[24]. If the 10% threshold is exceeded, then all costs are subject to the normal Cost Assessment process.

The AI framework is designed to reduce barriers to the development of coordinated offshore transmission networks by temporarily socialising the share of costs which are allocated to later users of the shared asset. This prevents the initial user constructing the asset bearing the cost of a more expensive coordinated design through its own network charges in the period between energisation and the connection of later user(s) to the shared asset. An Early Stage Assessment of project costs was developed as part of this framework to provide greater certainty to initial users of what costs would be allowed by Ofgem. Initial users of coordinated transmission assets can apply for Early Stage Assessment once they have a seabed lease and a Connection and Infrastructure Options Note.

Applying these approaches to the OFTO regime
Both the ASTI and AI approaches could help solve the problem of the Cost Assessment forcing developers to price cost disallowance uncertainty into CfD bids. Under either approach the baseline project cost should be set much earlier in the process than the Indicative Transfer Value (InTV) is currently, ideally between the planning permission award and route to market being secured either via CfD or Power Purchase Agreement (PPA). This would enable Ofgem to confirm that proposed design, procurement processes, and cost control measures are robust and would provide the added benefit of enabling the agreed baseline project cost to be input into the generator's CfD or PPA business model assumptions, which should reduce the uncertainty range for the *allowed* Final Transfer Value (FTV) costs which is priced into long-term subsidy support or PPA contracts.

To reduce the risk of disallowed costs being priced in, the first option follows an ASTI-like approach. An allowed variation in cost, for example 2.5% is set, and if the developer expects or finds costs change by more than this they may apply for a reopener to adjust the baseline. There is an agreed list of reasons for allowing a reopener[25] which reduces uncertainty, and one of the reopeners would consider uncertainties that are foreseen but cannot be effectively estimated during the project assessment, mirroring recent decisions in the ASTI regime[26] to provide such a mechanism. If the reopener request is accepted then the project cost is re-baselined with the accepted variation included, if it is not then the costs which exceed the threshold are disallowed. To ensure that costs remain correctly allocated changes in baseline project cost could be assessed at the Cost Assessment category level[27]. Projects remaining within the agreed tolerance would receive automatic approval of the FTV, significantly reducing the current 6-month assessment period per stage needed to carry out detailed bottom-up Cost Assessment across all expenditure categories, and providing greater certainty in the FTV during the transaction stage.

The second option to reduce the uncertainty from disallowed costs follows the AI approach, with a +/- 10% allowance for cost variation before triggering a full Cost Assessment. This approach would offer a margin which provides developers with increased certainty that cost disallowance will not result in losses. Generators still have incentives to keep delivery economic and efficient to minimise future TNUoS payments, to avoid the 10% threshold triggering detailed Cost Assessment, and to minimise the scale of disallowed costs in case the 10% margin is exceeded and a full Cost Assessment process takes place. In the event of a full Cost Assessment being necessary, the existing The Post-Transfer Revenue Adjustment (PTRA) mechanism[28] within the OFTO licence could be utilised to adjust the TRS to reconcile any cost variations, preventing potential delays to the OFTO transaction.

Applying a confirmatory approach would better recognise market forces, reduce the contentious use of previous benchmarks to assess projects which may have significantly different characteristics or technologies, and would reduce the resource intensiveness of the Cost Assessment process.

By replacing detailed benchmarking with a confirmatory process that verifies procurement and project management procedures rather than second-guessing market prices through benchmarking, the new regime would focus on correct allocation of costs and confirming that the procurement and project management processes resulted in the lowest cost outcome available from the market. This approach recognises that generators already face intense competitive pressure through CfD auctions, which provides an incentive to bid at minimum viable price, whilst maintaining appropriate consumer protection through the variance threshold. This should significantly reduce the risk of unpredictable cost disallowance and enable generators to make less risk-adjusted CfD bids, translating directly into reduced consumer electricity costs. By assessing costs only when an agreed threshold is exceeded, the administrative burden of multiple detailed Cost Assessment stages is removed. Finally setting a project cost benchmark before route to market is set, and after Ofgem has checked the design, procurement, and cost control processes, has the added benefit of somewhat reducing the uncertainty in the FTV which is priced into subsidy support or PPA contracts, which should result in less risk priced into CfD bids.

2.2 Recommendation 2:

The Cost Assessment guidance should be simplified, and legitimate financing costs allowed within the FTV, to reduce uncertainty and prevent unnecessary risk premiums in CfD prices.

The Cost Assessment process in general needs to rely less on the precedent and instead be based on clear guidance as the basis for decisions. There needs to be greater transparency of benchmark data and calculation methods, ensuring decisions are consistent and providing an escalation mechanism, consulting with industry on changes to guidance, and acknowledging that developers should not be penalised as a result of guidance having changed since procurement decisions were made.

With respect to financing costs, given the cost and scale of modern transmission assets the financial burden of pre- and post-construction financing costs borne by the developer is significant. Ofgem allows recovery of financing costs, known as Interest During Construction (IDC), incurred during a defined period before and during construction, ending once the transmission assets are "available for use for the transmission of electricity to the onshore network", typically coinciding with the issuance of the Completion Notice (ION-B)[29]. However, Ofgem applies limits to what is allowed to be recovered, and developers hold the view that some of these limits result in an arbitrary disallowance of genuinely incurred costs.

For example, in the recent Seagreen Cost Assessment Ofgem "determined that the economic and efficient development average, pre-FID development period to be 53 months based on past OFTO projects" and disallowed £1.5m of IDC costs incurred before that cut-off. Development times of projects may differ significantly for many reasons, and long lead time items such as transformers and cables may require significant down-payments many years before FID, therefore the 53-month cut-off would appear to be an overly simplistic and arbitrary point of reference for acceptable development time. It is also notable that the 53-month cut-off is not mentioned in the Ofgem Cost Assessment Guidance or in any previous Cost Assessment decisions.

With respect to post-construction costs there may be a period of many months between the completion of the transmission assets and the OFTO transaction date. During this time, generators must also meet ongoing operational and maintenance obligations whilst receiving no revenue for managing the transmission assets, however, they may begin generating operating revenue during this time and TNUoS charges are not incurred until after the OFTO transaction closes. With projects now exceeding £1 billion in value, the interest charges and O&M costs during this period can accumulate to tens of millions of pounds. The extension of the Generator Commissioning Clause (GCC) period from 18 months to 27 months increases the time allowed to complete divestment, therefore the period during which interest can accrue but not be recovered is also extended, resulting in increased financial risks to developers.

23 https://www.ofgem.gov.uk/sites/default/files/2024-11/EGL1%20Project%20Assessment%20Decision%20Final.pdf

24 https://www.ofgem.gov.uk/sites/default/files/2023-12/Early-Stage%20Assessment%20Guidance%20Document1702059641485.pdf

25 The reasons allowed under ASTI are: delays in obtaining planning approval and consents; acquisition of land / necessary land rights via compulsory acquisition; delays regarding seabed leasing or agreements for interaction with other third-party infrastructure; war, hostilities, or terrorist events; extreme weather conditions (lower than 1 in 10 probability); contractor/supplier/manufacturer insolvency or unavailability; pandemic or livestock epizootic; significant protestor action; legal challenge to procurement process; changes in law, regulation, and the international treaties applicable to the UK; availability of transmission system for build, testing and outages (e.g. if ESO calls planned action at short notice); unforeseen and significant ground or seabed conditions; unavailability of equipment or capacity globally in supply chain; unforeseen unexploded ordinance mitigation; significant archaeological discoveries; significant change to project scope; correlated delay in delivery of interlinked projects.

26 Eastern Green Link 1 – Project Assessment

27 Cost assessment categories used by Ofgem are as follows: CR1 — Costs overview Summary of all individual cost categories and cost movements CR2 — Offshore Substation Includes topside, foundations, transformers, control equipment, switch gear CR3 — Submarine Cable(s) All cost associated with cable supply, cable installation, cable burial, mattressing, interlinks CR4 — Onshore Cable(s) All costs associated with supplying and installing the onshore cable CR5 — Onshore Substation Includes civil contract, transformers, control equipment, switch gear CR6 — Reactive Substation Reactives, harmonics, SVC, mid-point compensation platform CR7 - Connection Cost for grid connection CR8 — Other Development, project management, insurance etc CR9 — Transaction costs https://www.ofgem.gov.uk/sites/default/files/2022-03/Offshore%20Transmission%20Guidance%20for%20Cost%20Assessment%202022.pdf

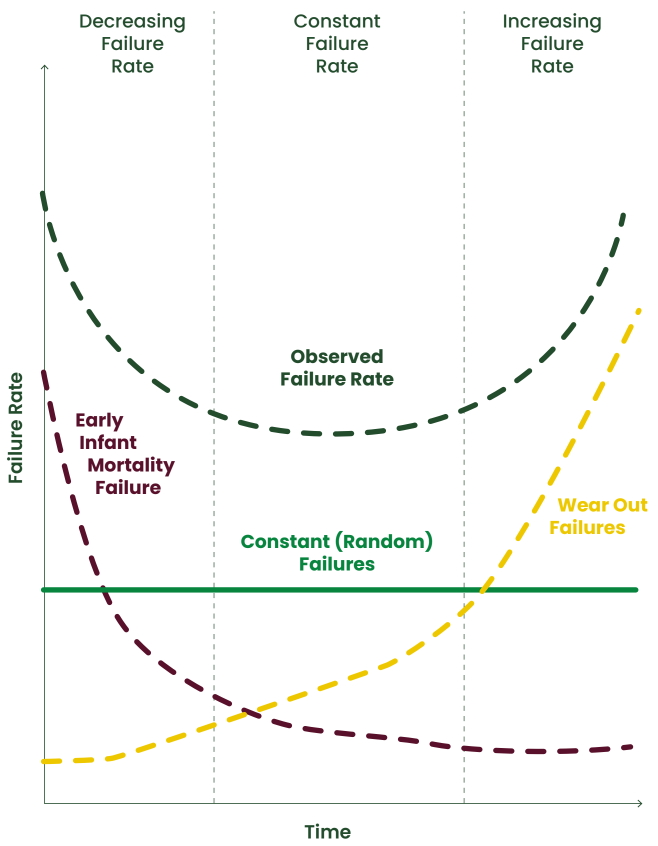
28 https://www.ofgem.gov.uk/sites/default/files/2024-02/Generic%20OFTO%20Licence%20TR11_V1.pdf

29 https://www.ofgem.gov.uk/sites/default/files/2022-03/Offshore%20Transmission%20Guidance%20for%20Cost%20Assessment%202022.pdf

2.2.1 Financing costs span pre-construction through to asset operation and snagging completion, but the Cost Assessment framework only compensates financing costs during construction, causing tens of millions of pounds in additional costs for large projects.

Construction financing risk does not end on asset completion but continues during the early operational period, this is a result of general infant mortality following commissioning which gradually reduces as early issues are identified and resolved (**Figure 5**). This characteristic is recognised by project financiers whom are often willing to re-finance projects after 4-5 years of operation once these risks have diminished.

Figure 5 — Failure rate bathtub curve for transmission assets (Source: CIGRE TB 642)



Under the current regime developers incur interest on all construction costs, from project inception and procurement of long lead time items up to the transfer payment from the OFTO. However, Ofgem does not allow developers to claim financing costs except for during the construction phase. For large projects with capital values exceeding £1 billion, even a few months of unrecovered financing costs can amount to tens of millions of pounds given that loan interest could be accruing at a rate of more than £10 million per month. This is exacerbated by the burden of significantly higher cost of capital for developers in comparison to OFTOs.

Ofgem's guidance states that the purpose of IDC is "to recompense [developers] for the economic and efficient costs of financing the development and construction of the Transmission Assets." Yet developers continue to incur financing costs on completed transmission assets until the divestment process is concluded. Developers attempt to ensure that construction is phased to minimise IDC, however efficient coordination of the multiple packages will not necessarily mean all elements of a project are active at the same time, and developers are unable to predict how long the transaction process will take. This unpredictability forces developers to price in substantial risk premiums to cover potential unrecovered costs during the transaction period.

2.2.2 Unrecoverable financing and O&M costs during the transaction period increases the overall risk profile of projects, passing additional costs to consumers and reducing the attractiveness of the GB market for generators.

Generators must factor these risks into Contract for Difference (CfD) strike price bids, passing uncertainty over costs to consumers through higher electricity prices. Following the same methodology used in 3.1.2 to estimate the impact of cost disallowance uncertainty on CfD prices, if generators price in a conservative estimate of unrecovered transaction-period costs (potentially £10-15m per large project), this could add £30 - 45m to CfD bids across the three previous tender rounds.

Uncompensated costs and asymmetric risk allocation during the transaction phase make UK projects less attractive
Multiple developers have expressed concerns about the Cost Assessment of accrued interest. The current framework creates uncertainty for investors regarding the full economic costs of projects. Significant unrecoverable costs emerging post-construction undermine the predictability that infrastructure investors require. As offshore wind development accelerates globally, the UK needs a competitive regulatory framework to maintain its position as a global leader in offshore wind.

2.2.3 The Cost Assessment guidance should be modified to allow pre- and post-construction financing costs to be recovered.

Extending IDC eligibility until the actual transaction completion date recognises that developers continue to incur financing costs on completed assets until they receive payment from the OFTO. This ensures the stated purpose of IDC to recompense developers for the economic and efficient costs of financing extends to the full period during which capital is deployed.

To implement this solution, it may be necessary to include forecast costs for the anticipated transaction period in the FTV calculation, with reconciliation through the Post-Transfer Revenue Adjustment (PTRA) mechanism[30] if actual transaction timelines differ from forecasts.

2.3 Recommendation 3:

Ofgem should publish clearer guidance on the decision-making process for critical and strategic spares within the existing Cost Assessment process, to remove disincentives on developers procuring spares which have long lead times or are critical for resilience.

Both critical spares, which are long lead-time items that are needed to maintain availability, and strategic spares which may be necessary to obtain to prevent future challenges in procurement, are extremely important for ensuring the resilience and security of the offshore transmission network. Examples of critical and strategic spares (which are not necessarily mutually exclusive) include HVDC cable and transformers, both of which have long lead times and particularly in the case of cable may be difficult to procure a decade or more after manufacture. The current Cost Assessment process creates uncertainty for developers around whether critical and strategic spares will be allowed or disallowed, despite their importance for maintaining system integrity. This uncertainty arises from limited guidance in Ofgem's existing Cost Assessment documentation and inconsistent decision-making on spares across different projects, as well as the fact that Ofgem does not distinguish between critical and strategic spares. The lack of clarity creates a disincentive for developers to procure critical and strategic spares during the initial manufacturing process when costs are most economic and manufacturing slots are available, potentially exposing the system to longer outages and higher costs should a failure occur and a spare not be available. The following sections set out the issues with the current approach and recommend improvements to the guidance.

2.3.1 There is insufficient detail on the process or principles which guide Ofgem's decision making for allowing or disallowing strategic spares costs.

Ofgem's current Offshore Transmission Cost Assessment Guidance[31] provides little detail on the process or principles which guide Ofgem's decision making to allow or disallow spares costs. This is particularly challenging for HVDC projects given the unique differences compared to HVAC technology. HVDC systems are typically much greater distances from shore and for critical high cost spares, such as HVDC cable and transformers, lead times are often long — with some developers quoting HVDC transformer lead times of 5 to 7 years. Therefore, procurement for these items typically takes place many years before the Cost Assessment process which leaves developers exposed to disallowed costs if Ofgem judges that the developer did not sufficiently justify the procurement of a strategic spare, or if the guidance changes in the intervening period.

2.3.2 Disallowed spares costs add unnecessary uncertainty which results in higher prices for consumers.

Generators will always act to minimise the uncapped losses which may arise from a lengthy outage on the transmission asset, and therefore they are incentivised to procure the spares they see as necessary whether Ofgem allows the costs or not. As set out in Recommendation 1, to manage commercial risks and meet their fiduciary duties some generators consider that they must price the risk of disallowed cost into the CfD or PPA price to have sufficient confidence to develop, impacting consumers through electricity bills. Developers depend on the guidance and precedent to price Cost Assessment risk into their business models, but Ofgem's guidance contains only four paragraphs on the treatment of spares and Ofgem's previous decisions have not been consistent.

Ofgem currently pre-approves spare cable lengths of up to 1km, and Ofgem does allow developers to claim for longer cable lengths if they can justify why it is necessary. However, given increasing distances from shore, and potential vulnerability of offshore cables to sabotage in an era of heighten geopolitical tensions, it is necessary to re-consider whether a 1km spare cable length is still appropriate. In some cases developers have successfully argued for greater than 1km of cable to be allowed, however the decision-making process which guides this determination is not set out in the Cost Assessment guidance document. Furthermore, Ofgem only allow spares for the initial transmission licence period, and not for the technical asset life which might be realised through an extension.

2.3.3 If a component failure did occur on a large transmission asset, and there was no strategic spare to replace it, there could be impacts on security of supply, net zero goals, and increased electricity prices.

If a spare is not ordered in the initial procurement, then an order will need to be placed upon failure or to enable asset life extension, at which point it could take months or years to procure a one-off replacement built to a design which may at that point be obsolete. In the case of procuring

30 https://www.ofgem.gov.uk/sites/default/files/2024-02/Generic%20OFTO%20Licence%20TRII_V1.pdf

31 https://www.ofgem.gov.uk/sites/default/files/2022-03/Offshore%20Transmission%20Guidance%20for%20Cost%20Assessment%202022.pdf

spare cable, it may be very difficult if not impossible to procure a short run of cable manufactured to an obsolete specification, manufacturing slots are difficult to secure, and it is not viable to retool production lines for a short run of cable.

In a hypothetical example of the impact of a cable or transformer failure impacting a large wind farm, if Hornsea 1 suffered a failure which resulted in 25% of the available energy being unable to be exported for one year, this would result in a loss of approximately 1.2 TWh in output[32], equivalent to the annual electricity consumption of Leeds[33]. This illustrates how even a partial failure on a transmission asset which requires a long-lead time spare to be ordered could be consequential for security of supply, net zero, and electricity prices. The impact on the generator and investors would also be significant, with lost revenues under the example above amounting to approximately £168m[34].

2.3.4 Ofgem should consult on more detailed guidance to reduce developer uncertainty over cost disallowance for strategic spares.

New detailed guidance should set out the principles which inform Ofgem's guidance on Cost Assessment for both critical and strategic spares and should provide more detailed guidance on the process and criteria Ofgem uses in determining whether spares costs are sufficiently justified or not. More detailed guidance on the scenarios under which additional cable and transformers are likely to be approved would be particularly beneficial.

Maintaining an adequate critical spares inventory, and ensuring that strategic spares are obtained at a time when they are available and cost effective, has the ultimate effect of minimising the risk of a large potential cost (the cost of the outage and lost generation due to a single failure, and the cost of obtaining obsolete spares). This solution would reduce developer uncertainty over disallowed costs and would send a positive signal to developers that they will not be penalised for procuring critical and strategic spares which Ofgem considers are in the interests of consumers to ensure a secure and resilient system.

32 https://www.windtable.co.uk/data?farm=Hornsea%201

33 https://lginform.local.gov.uk/reports/lgastandard?mod-area=E92000001&mod-group=AllLaInCountry_England&mod-metric=3791&mod-period=3&mod-type=namedComparisonGroup

34 Based on £140 per MWh strike price

Divestment Process

2.4 Recommendation 4:

Ofgem and DESNZ should continue to explore the appropriate measures and protections to limit the asymmetric negotiating power of OFTOs within the Generator Commissioning Clause (GCC) period.

Developers face criminal liability if the OFTO transaction is not completed before the end of the GCC period. Developers have highlighted that this creates an asymmetric negotiating position in favour of OFTOs, which do not have an equivalent incentive to close negotiations by a specific date. While OFTOs are incentivised not to delay negotiations since borrowing terms offered by their lenders are typically guaranteed for a period of 6 months, the potential impact of a delay beyond the end of the GCC is much greater for developers, and developers have reported instances of OFTOs leveraging this asymmetry by presenting unfavourable commercial terms late in the negotiation process.

Recently implemented reforms[35] to extend the GCC period to 27 months[36] alongside the extension of the preferred bidder stage by an additional 3-months recently announced by Ofgem[37] are expected to be beneficial by providing more time to reach an agreement, and DESNZ have informed industry that they plan to amend the offshore transmission licence exemption mechanism, including for GCC extensions, to allow them to provide exemptions more quickly. However, these reforms do not address the root cause of the negotiating asymmetry between developers and OFTOs during the GCC period.

2.4.1 Ofgem's most recent proposal to introduce an incentive for OFTOs to complete transactions by a target date rewards what should be a minimum expectation.

Ofgem has acknowledged that the negotiating asymmetry ultimately remains unresolved despite the reforms described above. Ofgem's recent consultation position[38] appears to rule out traditional penalty mechanisms to resolve this, including bidder bonds, preventing bidders from future tenders, or direct financial penalties. Instead, Ofgem is exploring financial benefits awarded to preferred

35 https://www.gov.uk/government/publications/the-planning-and-infrastructure-bill/guide-to-the-planning-and-infrastructure-bill; https://www.gov.uk/government/news/landmark-planning-and-infrastructure-bill-becomes-law

36 https://assets.publishing.service.gov.uk/media/6819dc13df188ba858873a6c/Annex_4_Planning_and_Infrastructure_Bill_Impact_Assessment_-_Offshore_transmission_owner_regime_reform.pdf

37 Further evolution of the OFTO Regime

38 https://www.ofgem.gov.uk/sites/default/files/2025-07/OFTO-Further-Evolution-of-a-Mature-Asset-Class.pdf

bidders who complete transactions by target dates. This approach constitutes an unwarranted payment from developers and ultimately consumers: there should be a baseline expectation that all parties negotiate in good faith. To reward OFTOs for meeting this minimum expectation at the expense of developers and consumers sets an inappropriate precedent and contravenes the principle that all parties should bear appropriate risk.

2.4.2 Ofgem's proposed solution does not resolve the impact on consumers – who pay to incentivise OFTOs either directly if the incentive is socialised, or via electricity prices if generators pay via TNUoS.

The asymmetry in negotiation power between the developer and preferred bidder means that the generator needs to carry more risk in its CfD bid on the expectation of achieving unfavourable and asymmetric commercial terms in the transaction. For example, the developer must price in the expectation that it may be compelled to accept indemnities to the incoming OFTO which they would not otherwise have offered were it not for the GCC deadline. This results in inefficient costs being folded into CfD bids, and cross subsidisation of the OFTO assets from the wind farm.

Any incentive for OFTOs to complete a transaction by a target date will also ultimately fall on consumers, either directly paid by consumers, or if the incentive is paid by generators, through CfD bids. Any payment for meeting what should be a minimum expectation represents poor value for money for consumers.

2.4.3 Ofgem and DESNZ should continue to explore the appropriate measures and protections to limit the asymmetric negotiating power of OFTOs within the Generator Commissioning Clause period.

Whilst recognising Ofgem's relevant concerns regarding the potential impacts of financial penalties on OFTOs in case transaction dates are missed, developers' position is that applying penalties on OFTOs that are judged to be acting in bad faith is the most appropriate solution. Ofgem should continue to explore the role of penalties which prevent the use of unfair negotiating tactics which leverage GCC negotiating power asymmetry, and should explore how concerns with this approach could be addressed, for instance by including mechanisms which protect OFTOs from penalties if delays result from the developer or both parties equally, or where OFTOs do not demand unusually onerous commercial terms as part of the negotiation. Whilst this would require Ofgem to take a more active role in overseeing negotiations, this would also be necessitated by the application of an incentive since OFTOs would price the receipt of the incentive into their bids and would likely challenge the reasoning behind an Ofgem decision to deny the incentive payment.

Developers welcome DESNZ's announcement that work to amend the mechanism for providing GCC exemptions is ongoing[39], potentially removing the need for parliamentary time to extend the GCC, and request that DESNZ consult with industry as soon as possible on any forthcoming changes to the extension mechanism.

39 Offshore Transmission Owner (OFTO) regime: update on policy reforms GOV.UK

Operation and Maintenance Incentives

2.5 Recommendation 5:

Operations and Maintenance (O&M) incentives should be strengthened to better incentivise best practice in asset management.

OFTOs are incentivised to maintain the transmission asset at the highest availability whilst minimising costs. The existing availability incentive provides financial rewards when OFTOs achieve annual availability above 98% and penalties when availability falls below this threshold. Whilst this framework has proven effective in maintaining system availability, it provides limited incentive for comprehensive asset management practices beyond those directly impacting availability metrics. The introduction of bi-pole HVDC technology which has less redundancy, and so is at greater risk of loss of availability following a failure, makes it increasingly important to ensure that best practice maintenance and timely repairs are strongly incentivised.

2.5.1 Current O&M incentives may not adequately address broader asset health concerns.

The availability incentive focuses exclusively on maintaining transmission capacity, giving OFTOs operational freedom to prioritise maintenance activities as they see fit, provided availability targets are met. This structure may inadvertently create incentives to defer expenditure on activities that do not directly impact short-term availability, including maintenance of auxiliary equipment.

Once the annual availability of the transmission asset goes below 78% the maximum penalty under the availability incentive applies, which is a penalty of 10% of the annual TRS value in the relevant year every year for a period of 5 years[40]. Once this floor is reached any further loss in availability results in no further financial impact on the OFTO, and there is no longer a financial incentive for an OFTO to resolve the fault with any expedience. In fact, in this situation the financial incentive is for the OFTO to pursue the least expensive route to repair rather than the quickest route to repair, however there is a risk of enforcement action by Ofgem.

2.5.2 Where O&M incentives break down there is the potential for significant revenue loss and costs to be imposed on generators.

Generators bear disproportionate financial exposure when transmission asset availability deteriorates. Whilst OFTOs face a maximum penalty of 10% of their TRS revenue for 5 years, generators face much larger losses from their

40 The maximum penalty which applies once 78% availability is reached is 50% of the TRS is in the relevant year, spread over 5 years, so the revenue loss is limited to 10% of the annual TRS for 5 years. Even if a further availability reducing event occurs within the 5-year period the revenue loss remains capped at 10% of TRS.

inability to export power to the grid. For a modern offshore wind farm, prolonged transmission outages can result in revenue losses that far exceed the penalties faced by the OFTO, creating a significant misalignment in risk exposure between the two parties.

2.5.3 An O&M scorecard should be introduced within the existing availability incentive to ensure that OFTOs execute their O&M regularly and on time.

To address the limitations of the current availability-focused incentive structure, Ofgem should consider implementing an O&M scorecard within the existing availability incentive framework, linked to broader asset management performance. This scorecard would be assessed primarily by Ofgem, with input from connected generators, and would focus on proactive asset management beyond simple availability metrics. Whilst the transmission asset availability should remain the primary determinant of the incentive value, a small proportion of the overall incentive value could be tied to the scorecard, providing an incentive to maintain O&M best practice across all OFTO assets, including auxiliary assets, and providing a remaining incentive even if annual availability has dropped below 94%.

2.6 Recommendation 6:

Generators must retain the option to provide O&M services to OFTOs as the primary risk-bearing party.

The OFTO regime is predicated on the principle of removing generator control over the transmission asset whilst ensuring limited revenue exposure for OFTOs so that they can attract low-cost capital. This creates significant misalignment in risk and O&M incentives: because the penalties on OFTOs are capped lower than the losses a generator could incur from a transmission outage, the operational risk is transferred from OFTOs to generators.

Under the current OFTO regime, some generators have developed a practice of offering O&M service contracts to prospective OFTOs during the tender process. These offers, which bidders can choose to accept at the Invitation to Tender (ITT) stage, typically involve the generator providing comprehensive O&M services for the transmission assets at below market value.

2.6.1 Ofgem has expressed concern over the trend of generators providing O&M services to OFTOs.

Ofgem has recently expressed concerns about this trend[41] commenting that whilst there are clear benefits to this arrangement, that it "is not necessarily in the spirit of the regime" and that it can "undermine the effectiveness of the availability incentive". Specifically, Ofgem's concerns are around the lack of control an OFTO has over their own asset and the impact on competition as OFTO bidders have little choice but to take a below market O&M offer in a price-based process.

2.6.2 Preventing generators from providing O&M services would be regulatory over-reach and would result in OFTOs and generators facing increased risk and cost, resulting in higher cost to consumers.

The discounted fees which generators offer to OFTOs to secure selection for O&M contracts, delivers cost efficiencies for consumers by reducing the overall cost of the TRS. There could also be benefits in reducing the overall costs of insurance for the generator and OFTO, because the generator already has a track record already of maintaining the assets at the point of transfer.

Whilst the generator may factor in the actual cost of delivering the O&M into its CfD or PPA, generators can often have practical advantages over OFTOs which mean they may be able to deliver O&M more efficiently, such as better understanding of the design specifications, experience from commissioning and operating the assets prior to divestment, easier access to vessels, and pre-existing contractual relationships with equipment manufacturers on which warranty commitments may be reliant. If generators were prevented from offering O&M services then these efficiencies would be lost.

The award of O&M services is a commercial process and outside of Ofgem's core duties, but furthermore it is unlikely that provision of O&M services meets the EU definition of control over transmission assets from which UK legislation derives. An O&M contract does not confer voting rights, power to appoint members of governing bodies, or provide a majority shareholding[42]. Indeed, there are examples of projects within the EU where Generators have actual control of transmission assets serving their projects, in compliance with EU unbundling legislation (see Appendix 2).

2.6.3 Ofgem should remove doubts over whether generators will continue to be permitted to provide O&M services.

As the party most exposed to the risk of a transmission outage, it is highly important that the Generator retains the right to provide the O&M services to the OFTO as the generator needs to be able to manage this risk as far as possible.

The ability for generators to provide O&M services helps to mitigate the significant risk which is put on generators by the transfer of the transmission asset to OFTOs. Whilst there may be potential risks identified by Ofgem which could result from this arrangement, such as in the event of contractual disputes, overall this arrangement offers a good balance by attracting low-cost capital to the OFTO regime and minimises cost to consumers. This is achieved by aligning the incentives of the generator to maximise generation with the maintenance of the transmission asset, enabling generators to leverage their extensive capabilities and vessel access to provide high-quality, low cost, and timely O&M services. Given the importance of generator provided O&M to the sector, it would be highly beneficial for Ofgem to clarify its position as to whether it views this arrangement as compatible with the regime on an enduring basis.

41 https://www.ofgem.gov.uk/sites/default/files/2025-07/OFTO-Further-Evolution-of-a-Mature-Asset-Class.pdf

42 Investing in Energy in the EU — Navigating the Ownership Unbundling Rules | Cleary M&A and Corporate Governance Watch

End of Tender Revenue Stream (EoTRS)

2.7 Recommendation 7:

Ofgem should make contingency plans for incumbent OFTOs preferring to divest or decommission the asset rather than continue with ERS.

The success of the EoTRS policy framework depends on incumbent OFTOs choosing to participate in the extension regime. Whilst Ofgem's policy development to date has focused primarily on establishing the mechanisms through which extensions would operate, less attention has been given to the question of whether incumbent OFTOs will be sufficiently incentivised to pursue an ERS. The following section examines the alternatives available to incumbent OFTOs at the end of the TRS period, the economic factors that might lead OFTOs to prefer divestment or decommissioning over continuation with an ERS, and the implications of this scenario for generators, consumers, and the credibility of the OFTO regime as a whole.

2.7.1 Ofgem's current policy position on EoTRS is overly dependent on an incumbent OFTO agreeing to an extension, however this is far from certain since OFTOs may be more incentivised to divest or decommission the asset.

Ofgem states that it "expect[s] incumbent OFTOs to be well positioned to operate transmission assets in an extension period"[43] and EoTRS policy is currently designed around the incumbent remaining in place, with the backstop of competition from a competitive re-tender to moderate the incumbents ERS bid.

From the incumbent OFTOs perspective, the decision on whether to agree to an extension depends on whether the return which they can expect to achieve during the is higher than the return that the OFTO could make by divesting or decommissioning the asset, realising the asset transfer value, and re-investing the proceeds. This calculation will be significantly influenced by Ofgem, which will approve both the ERS, and if relevant the asset transfer value, after which the generator will need to determine whether the resulting ERS enables life extension of the OWF. If the OFTO calculates that the risk rated return of the ERS is insufficient, it may be more incentivised to divest or decommission assets.

The OFTO has three alternatives to continuing with the ERS:

- Divest the asset to a new OFTO and re-invest the capital: the OFTO recovers the fair market price for the assets in line with Ofgem's principles for asset valuation[44] and re-invests this capital where it could attract a higher return (the mechanism to set the asset transfer value is unclear however Ofgem has indicated that it would be based on the Net Alternative Value (NAV)[45], which will likely be the scrap value as a minimum).
- Decommission the assets (the following options should only be possible if the generator does not wish to extend):
  — Re-deploy assets in another location — assets such as transformers and switchgear will still have useful technical life at the end of the TRS period and could be re-deployed.
  — Recover the scrap value — based on public data and current mineral scrap prices, the value for some early tender round offshore wind projects could be in the low £10's of millions by the early 2030's, whilst larger projects from later tender rounds could have scrap mineral values approaching £400 million by the 2040's[46]. OFTOs awarded through Tender Rounds 1-6 do not make provision for full cable recovery in their decommissioning plans, but depending on mineral prices there may be a business case to decommission and recover the cables for scrap value.

43 https://www.ofgem.gov.uk/sites/default/files/2024-01/EoTRS%20Decision%2C%2024%20January%202024.pdf

44 https://www.ofgem.gov.uk/sites/default/files/2024-01/EoTRS%20Decision%2C%2024%20January%202024.pdf

A decision not to proceed with the ERS and to pursue one of the three options above is made more likely by the fact that some OFTOs appear to have built residual value assumptions into their TRS bids. Ofgem have been consistent in their position that OFTOs should assume no residual TRS capital value in their ERS assumptions, since the capital cost of acquiring the asset should have been paid off at the end of the TRS, and that OFTOs assuming a residual value at the end of the TRS do so at their own risk[47]. OFTOs which have taken high-risk aggressive bidding strategies in OFTO tenders may be faced with a dilemma that they need an ERS period to recover remaining TRS capital value, but that Ofgem have explicitly stated that they expect there to be no residual TRS capital value in the ERS bid. There is evidence from Ofgem consultations that some incumbent OFTOs are in this position:

"One OFTO also set out their understanding of 'residual value', saying that they expected there to be some residual value left at the end of the TRS because they had modelled a longer term than the TRS when they made their original bid, and not to have written down the whole asset value through the TRS term. They noted that as a result there may be less of a reduction from the TRS than Ofgem may be expecting, as some OFTOs have factored in possible life extensions when bidding for the TRS.[48]

Two OFTOs noted that an incumbent OFTO might prefer to decommission the assets rather than accept the extension terms proposed. Another queried the legal route available to force a transfer of OFTO assets with a competitive tender.[49]

This poses a difficult question for Ofgem on how to cost assess an ERS bid which carries over significant material undepreciated asset value from the TRS into the ERS. On the one hand Ofgem has explicitly stated that they do not expect OFTOs to build in TRS capital recovery into the ERS, but on the other hand if the incumbent decides that it is preferable to divest the asset rather than accept a lower ERS then a re-tender will be triggered. In that case the ERS is also expected to be inflated, because following a re-tender the cost of financing the asset transfer value from the incumbent to the new OFTO, as well as the cost of the re-tender process itself, would need to be factored in.

With respect to the legal route to force a transfer of OFTO assets should an OFTO prefer to decommission the assets rather than divest them, Ofgem does have the power to effect a property transfer scheme under the Electricity Act[50]. However it seems unlikely that this approach would be very attractive to Ofgem, firstly because it would result in significant damage to the credibility of the OFTO regime amongst investors; and secondly that the time needed to conduct a re-tender process, and if that fails appoint an OFTO of Last Resort and implement a property transfer scheme (including any potential legal challenges) is incompatible with the already compressed timelines at the end of the TRS. Finally, a property transfer scheme would still require the incumbent OFTO to receive the fair value of the asset determined by Ofgem, if the financing costs of an incoming OFTO of last resort are passed onto the generator through the ERS there is a high likelihood that the generator would no longer have a positive business case for life extension.

2.7.2 Ofgem risks a situation where incumbent OFTOs are able to leverage the reality that there is no legitimate prospect of competition to ensure fair value for generators and, by extension, consumers.

The emerging dependency on the incumbent OFTO under the current policy landscape presents two significant risks for the credibility of OFTO regime:

1. It fails to provide sufficient competition to protect generators, and in the process impacts consumers

45 Ofgem defines the NAV as "the realisable value from the alternative use of the asset, net of the costs incurred to realise that value. Alternative use might constitute scrap value or the reuse of the transmission assets, for example to connect other generators or customers, reducing the need to build new transmission assets." https://www.ofgem.gov.uk/sites/default/files/2022-06/2nd_Consultation_EoTRS_Final.pdf

46 Based on project specific data and assuming 5% annual inflation from current high grade scrap copper prices to end of TRS https://www.metal.com/en/prices/201410100003

47 https://www.ofgem.gov.uk/sites/default/files/2022-06/2nd_Consultation_EoTRS_Final.pdf

48 https://www.ofgem.gov.uk/sites/default/files/2024-11/Decision_health_reviews.pdf

49 https://www.ofgem.gov.uk/decision/end-ofto-tender-revenue-stream-decision

50 https://assets.publishing.service.gov.uk/media/5a80c002ed915d74e62303b1/Electricity_Act_1989__Energy_Bill_2015-16_Keeling_Schedule_.pdf

by putting at risk the continued generation from renewable capacity at end of TRS.

2. It risks damaging investor confidence should a situation arise where the incumbent is more incentivised to decommission the assets than to continue with the ERS, resulting in either generation assets being stranded or Ofgem being forced to implement a property transfer scheme from the incumbent OFTO to an OFTO of last resort.

The consequences for the generator of a failure by Ofgem to appoint a replacement OFTO, or even a delay beyond T-2.5, are potentially significant. Given that generators expect to require 6 years to decommission a wind farm, waiting until T-2.5 to make a decision on decommissioning means that the generator will either have stranded assets for 3-4 years, or will bear the cost of a prolonged period of parallel extension and decommissioning planning.

2.7.3 Ofgem should publish contingency plans for a situation where a generator wishes to extend but the incumbent OFTO wishes to decommission the assets or the ERS cost is too high. Ofgem should also provide greater clarity on the re-tender process and asset transfer value, re-tender timelines and alignment with decommissioning, and the compatibility of the OFTO of Last Resort and property transfer scheme processes with EoTRS timelines.

Ofgem should develop and publish comprehensive contingency plans which provide greater clarity on the mechanisms that Ofgem has identified as being available should an incumbent OFTO prefer to divest or decommission assets rather than continue with an extension, namely: the re-tender process, asset valuation methodology, and an OFTO of last resort mechanism and associated property transfer scheme.

By providing clarity on these three areas Ofgem would address the uncertainty that represents the greatest risk to the generators business case for life extension. Furthermore, the existence of well-defined contingency plans would strengthen Ofgem's negotiating position with incumbent OFTOs by demonstrating credible alternatives to accepting commercially unattractive ERS terms, thereby helping to address the problem of asymmetric negotiating power and providing better protection for generators and consumers against excessive ERS costs or early decommissioning of offshore wind farms.

Re-tender process
Ofgem should publish detailed guidance on how the competitive re-tender process would be conducted, particularly the ERS calculation mechanism and Ofgem's approach to ensuring that that a fair outcome is reached for all parties. The re-tender process must also address the inherent competitive disadvantage faced by potential successor OFTOs, who would likely need to incorporate an asset transfer value into their bid. Finally, Ofgem should clarify what will happen if an OFTO is not appointed by the time the incumbent's licence period ends.

Asset valuation methodology
Whilst Ofgem has stated it will consider the approach to OFTO asset value further and consult as necessary, this uncertainty represents the main barrier to generators making informed decisions on life extension. Ofgem must establish and publish a clear methodology for determining asset transfer values at the end of the TRS period or during a property transfer scheme.

OFTO of last resort mechanism and associated property transfer scheme
Despite the challenges associated with an OFTO of last resort and property transfer scheme, this is the only safeguard against a scenario where an incumbent OFTO is committed to decommissioning assets whilst a generator is committed to life extension.

The OFTO of last resort mechanism referenced in Ofgem guidance and OFTO licence conditions remains untested and lacks the detailed implementation framework necessary to provide confidence to generators. Ofgem should publish guidance on how this mechanism would apply in the context of a failed ERS re-tender, including whether and how an ERS value would be determined for an OFTO of last resort, and the expected timeline to appoint an OFTO of last resort and implement the asset transfer process. Given that the activation of this mechanism would need to align with the already compressed ERS decision-making timelines at the end of the TRS, Ofgem must ensure that the OFTO of last resort framework can be deployed rapidly and effectively.

2.8 Recommendation 8:

Generator ownership should be allowed as a backstop to a failed ERS re-tender to ensure that there is effective competition to protect consumers and to provide generators with increased confidence to commit to life extensions.

The UK's unbundling regulations originate from EU law are set out in the UK 1989 Electricity Act. The principle of the unbundling rules is to legally separate owners of transmission networks from companies that generate or supply the energy, in order to prevent companies abusing their position as transmission owners to restrict market access to their competitors.

In general, the European Commission approves offshore grid ownership by generators and treats the simultaneous participation in transmission activities and in production/supply activities as compatible with the unbundling rules as long as it can be proven that it does not give rise to any potential conflict of interest, limited third-party access to the grid, or additional costs to the consumers[51]. Given that radial offshore transmission grids are designed to be used by a single generator, it is not possible for a single entity which is both the generator and the offshore Transmission Owner to limit a competitor's market access. Two examples of projects incorporating generator ownership of offshore transmission assets in Denmark and Poland are provided in APPENDIX 2 - International perspectives on generator ownership of offshore grid transmission.

Allowing generator ownership of radial transmission links in the UK may require changes in legislation, either to redefine the meaning of transmission asset so that it does not apply to radial offshore connections to the wind farm, or to permit licence exemptions for generators under specific circumstances. One such licence exemption already exists, the Generator Commissioning Clause (GCC) provides an exemption for generators to own transmission assets between energisation and the end of the GCC exemption period, by which date the generator is required to have divested the assets to the OFTO.

2.8.1 There is unlikely to be true competition for the ERS.

OFTOs have indicated that they would be unlikely to bid against an incumbent
In Ofgem's End of Tender Revenue Stream consultation[52] four OFTOs indicated that they would be unlikely to bid against an incumbent, and that it would be unlikely that bidders would be willing to hold firm price commitments for 3 to 4 years until a licence commences. Potential reasons why incumbents might be unlikely to bid are: first, that the value of the ERS is relatively low compared to the TRS; second, that bidders are at a disadvantage to the incumbent OFTO which has a much deeper understanding of the condition and operational history of the assets; third, any competing OFTO would need to incorporate an asset transfer value into their bid to purchase the assets from the incumbent whilst the incumbent faces no such acquisition cost, creating an inherent competitive disadvantage for competitive bidders; and fourth, that the successful bidder must assume responsibility for the decommissioning liabilities, which adds significant additional risk relative to the value of the ERS.

51 https://www.clearymawatch.com/2016/02/investing-in-energy-in-the-eu-navigating-the-ownership-unbundling-rules/#_ftn3

52 https://www.ofgem.gov.uk/sites/default/files/2024-01/EoTRS%20Decision%2C%2024%20January%202024.pdf

2.8.2 The incumbent OFTO is incentivised to leverage its asymmetric negotiating position to maximise the value of the ERS and may have a back-up exit strategy in realising scrap value

The incumbent OFTO is likely to have asymmetric bargaining power during the ERS negations, with respect to both the generator and Ofgem. The generator may have already incurred sunk costs in life extension planning, whilst Ofgem faces the risk of an ERS re-tender process which is untested and seems unlikely to attract many bidders. The OFTO of last resort mechanism is also untested and its activation would risk undermining the credibility of the OFTO regime.

As commercial entities OFTOs are required to maximise returns for shareholders, the asymmetric ERS negotiating power creates scope for them to do so at the expense of the generator and consumers. The OFTO will naturally aim to maximise the ERS value it receives, but importantly the normal market discipline that might moderate pricing, namely the OFTO's incentive to set reasonable terms to secure the life extension opportunity, and competitive pressure is significantly weakened by the challenges described above and the availability of an alternative exit strategy.

The incumbent OFTO may hold significant scrap value in the assets, potentially ranging from tens to hundreds of millions of pounds, which they could realise through decommissioning rather than committing to an ERS arrangement. Increasing copper prices mean that cable recovery could be financially viable even if it was not factored into the original decommissioning plan. This could significantly alter the negotiating dynamic because OFTOs may be in a stronger position to demand commercially unattractive terms with reduced concern for whether Ofgem accepts their ERS proposal, or whether the generator ultimately agrees to proceed with an extension.

There are risks to this approach for the OFTO, first that competition for the ERS or the OFTO of Last Resort process are effective in securing a new OFTO; and second that the transfer value might not meet the OFTOs expectations if Ofgem consider that only the materials planned to be recovered in the decommissioning plan could legitimately be included in any scrap value which might be factored into the asset transfer value. In OFTO tender round 1-6 projects most of the high value cable is planned to be left buried in the seabed and therefore would, most likely, not be considered as part of the scrap value.

2.8.3 Generator ownership of transmission assets as a backstop to failed ERS re-tender could reduce the asymmetric negotiating position of the incumbent.

Enabling generators to assume ownership of transmission assets following a failed ERS tender process would ensure that there is credible competition for the incumbent, because a generator is more incentivised than any other party to act in support of keeping the transmission assets online. The possibility for a generator to assuming control in the event of a failed re-tender would significantly moderate an OFTOs natural incentive to exploit the lack of competition from other OFTOs to maximise the ERS value. This backstop would not fully resolve a situation where the generator was committed to extend but the OFTO was committed to decommission the assets, but at least the generator would have the option to offer the OFTO a small premium over the scrap value to acquire the assets – should the business case be strong enough to accommodate this. Generator ownership as a credible alternative would therefore help restore credible competition to ERS negotiations, ensuring that pricing more accurately reflects efficient costs and appropriate risk allocation.

2.9 Recommendation 9:

To enable life extension of older assets where the costs of an ERS may be disproportionate to the remaining benefits, generator ownership of transmission assets should be allowed for a period of five years or less.

Offshore wind projects from early tender rounds approaching the end of their Tender Revenue Stream period present a unique set of challenges for life extension decisions. These smaller, older wind farms were developed with technologies and at scales substantially different from modern offshore wind projects, and their remaining technical and economic life may be limited.

2.9.1 The costs of re-tendering may be disproportionate to remaining benefits for older assets.

For older, first-round offshore wind farms with limited remaining operational life, the business case for life extension is typically very tight. In this situation the cost of conducting an ERS competitive re-tender process may result in life extension becoming financially unviable. The tender process involves considerable expense and resource commitment from all parties involved. Whilst Ofgem has not published definitive estimates, stakeholder feedback suggests that the administrative burden of conducting a competitive tender, including due diligence requirements, asset valuation exercises, legal costs, and Ofgem's evaluation process, would represent a significant cost that must ultimately be recovered through the ERS. Furthermore, feedback from OFTOs to Ofgem consultations indicate a lack of competitive interest in bidding against incumbents which means that the costs of running a tender process may deliver negligible consumer benefit whilst materially damaging the generator's business case for extension.

2.9.2 Some wind farms may be forced to decommission a few years earlier than would be the case without a re-tender.

For smaller projects with perhaps only five years of viable remaining life, these costs could result in the business case becoming unviable, forcing generators to opt for decommissioning rather than extension despite the technical capability for continued operation.

The impacts of premature decommissioning are discussed in Section 1.3.4. For generators, it would mean writing off potential revenue streams from assets that remain technically capable of operation, reducing returns on initial capital investment. From a consumer perspective, early decommissioning of operational wind farms would result in the loss of low carbon generation capacity during the 2030s, precisely when the UK aims to decarbonise the electricity grid.

2.9.3 Generator ownership at end of TRS (and ERS) could enable life extensions for short periods (< 5 years) which would otherwise not be economic.

To enable the life extension of older offshore wind assets where a competitive ERS tender would be disproportionately expensive relative to the remaining benefits, Ofgem should permit generator ownership of transmission assets for extension periods of five years or less. This solution would operate under specific circumstances where Ofgem determines, based on the incumbent OFTO's ERS submission and associated Cost Assessment, that the costs of conducting a competitive re-tender would materially impair the generator's business case for extension. The generator ownership period would be limited to a maximum of five years.

Under this arrangement, generators would be granted a licence exemption to own and operate the transmission assets for the limited extension period, similar in principle to the Generator Commissioning Clause which already permits temporary generator ownership during the construction and commissioning phase. This approach recognises that for radial offshore transmission connections serving a single wind farm, there is no third-party access to restrict and therefore no conflict with the underlying policy intent of unbundling regulations, which seek to prevent transmission owners from limiting competitors' market access.

The five-year threshold is appropriate as it represents a limited, defined period that balances the need to maximise the productive life of existing assets against the risk of undermining the broader OFTO regime. For older assets, five years may represent the maximum technically justifiable extension period given equipment age and condition. By restricting generator ownership to these circumstances, the solution maintains the integrity of the OFTO regime for longer-life extensions whilst providing a pragmatic route to extend operation of wind farms where uncertainty over the remaining technical life and a marginal business case would not otherwise support the cost of a competitive re-tender.

This solution delivers benefits to all stakeholders: generators gain viable business cases for life extension; consumers benefit from continued low-cost generation and avoid paying for competitive tender process that would deliver no value, OFTOs receive a transfer value and are relieved of decommissioning liabilities, and the UK's net zero objectives are supported by maximising the productive life of existing renewable infrastructure.

International precedents in Denmark and Poland demonstrate that generator ownership of offshore transmission connections is compatible with EU unbundling principles, suggesting that implementing this approach in the UK would not require fundamental changes to regulatory philosophy, though it may necessitate amendments to domestic legislation or expansion of existing licence exemption frameworks.

2.10 Recommendation 10:

EoTRS policy should be updated to provide generators with greater certainty on the business case for extension by defining an ERS calculation mechanism, providing guidance on asset transfer value, and sharing the OFTO ERS cost forecasts received at T-5 and T-4 with generators.

EoTRS policy was introduced to enable offshore wind farms to continue operating beyond their initial Tender Revenue Stream period. Whilst the policy framework has been established, there are concerns that it does not provide sufficient certainty for generators to make timely and informed decisions about life extension versus decommissioning. The absence of an Extension Revenue Stream (ERS) calculation mechanism, uncertainty over asset transfer values in competitive re-tender scenarios, and delays in receiving financial information which determines the business case mean that generators face considerable commercial risk when evaluating life extension.

2.10.1 Generators are concerned that current policy does not provide sufficient certainty to commit to life extension

The first ERS Cost Assessment and decision on competitive re-tender could be needed as soon as March 2028 for the Barrow project[53]. To commit to life extension, generators require clear visibility of long-term costs and revenue streams that will enable recovery of the capital investment needed for refurbishment and upgrades and ongoing Operations and Maintenance costs during the extension.

If there is not sufficient information available to generators to confidently decide on life extension, then the least risky option is to decommission the wind farm, because a single round of decommissioning planning and implementation is already priced into the generator's business model and this results in no risk of stranded life extension investments.

Three reasons for generator uncertainty over life extension business case are set out below:

1. **The business case for life extension of offshore wind farms may be marginal**
   The business case for life extension of an offshore wind farm may be marginal, especially for smaller projects from early tender rounds which do not have the benefit of economies of scale and are more impacted by the loss of the more generous subsidy support that enabled their development. For these projects the forecasted revenues after the initial support period ends may only be slightly higher than ongoing operating costs, leaving limited profit margin. The business case for life extension for these projects is likely to be highly sensitive to external factors such as the ERS value and movements in electricity prices.

2. **Since there is no clear methodology to estimate the ERS, and the actual ERS is determined too late to make a decision on decommissioning, an early commitment to decommissioning may be a less risky option for many projects**
   Ofgem has not published a detailed mechanism for how the ERS might be calculated or Cost Assessed, so generators are unable to model ERS scenarios with confidence. Under the current timeline generators do not receive the ERS until T-3 (or around 6 months later in case of a re-tender), which is too late to make a timely decision on life extension vs. decommissioning (for which planning must being at T-6). Therefore, generators intent on life extension must commence the decommissioning process in parallel to life extension planning and investment, until such time as the business case to make a final decision is known. In the event of a longer life extension much of the investment in decommissioning could be lost because the more time passes the greater the likelihood that the decommissioning process would need to be re-started from the beginning. This could deter generators from committing to life extension.

53 Barrow OFTO | UK Energy Transmission Infrastructure | Amber

3. **There is no decision from Ofgem on how the asset value will be calculated in case of re-tender (or transfer to generator)**
   A significant point of uncertainty in calculating the ERS is that in the event of a competitive re-tender, there is no Ofgem guidance on the methodology that will be used to set a transfer value for the transmission infrastructure from the incumbent to the successor OFTO. Based on previous Ofgem guidance this transfer value is expected to, at the least, be equal to the scrap value of the asset - which could be tens or hundreds of millions of pounds. The assumptions in the decommissioning plan should also be factored into the scrap value calculation so that value is not assigned to assets which are planned to be left buried. The resulting transfer value would have to be financed and added to the ERS and given that the generator business case for extension is expected to be marginal this could result in a decision against the life extension of the wind farm.

2.10.2 Unnecessary early decommissioning could have negative impacts on net zero and result in higher cost to consumers during the 2030's.

Should generators choose to decommission offshore wind farms at the end of TRS instead of life extension there is the potential for large amounts of capacity to come offline earlier than is technically necessary, resulting in increased cost to consumers and directly undermining the UK's ability to meet its net zero commitments.

2.10.3 Ofgem should move at pace to provide greater clarity on the ERS calculation mechanism and asset transfer value and should share the ERS cost forecasts it receives from OFTOs at T-5 and T-4 with generators.

Ofgem should move at pace to publish a mechanism for calculating the Extension Revenue Stream, including clear guidance on Cost Assessment principles. This would enable generators to model ERS scenarios more effectively to provide increased confidence in decision making on life extension.

Ofgem should publish definitive guidance on the determination of asset transfer values in the event of competitive re-tender at the end of the initial revenue period. This guidance should address whether transfer values will be based on regulatory asset value, market value, scrap value, or an alternative approach, and should provide worked examples to illustrate the calculation methodology. Clear asset valuation guidance would remove a major source of uncertainty from generators' ERS modelling and would also be needed to enable generator ownership of the transmission asset as a backstop to a failed ERS re-tender, as proposed in Recommendation 8. In setting the guidance for asset transfer value Ofgem should be mindful that this decision will have significant consequences for the viability of offshore wind farm life extension under all scenarios where the incumbent does not remain in place (i.e. a new OFTO, generator back-stop, or OFTO of last resort). Data on generator business cases for life extension should be reviewed as part of the process of determining an appropriate mechanism.

Ofgem should ensure the indicative ERS cost forecast received from OFTOs at T-5 that is shared with the generator is useful and robust. Whilst the T-5 figure would remain indicative and subject to final Cost Assessment, if a usable level of information is provided it would enable generators to make more informed choices about life extension decisions at an earlier stage, preventing costly decommissioning and life extension processes running in parallel for an extended period.

2.1 Recommendation 11:

Ofgem should continue to gather evidence to support a decision on extending the 25-year TRS period, and publish an indicative timeline for a decision.

Extending the TRS duration is a potential solution to many of the challenges associated with EoTRS policy. Rather than attempting to manage the complexities of extending transmission asset licences after 25 years, with all the associated uncertainties around asset valuation, competitive re-tender processes, and commercial negotiation, extending the initial TRS period would provide greater certainty from the outset for generators and OFTOs alike. This approach would align the regulatory framework more closely with the increasing technical lifespans of modern offshore wind farm assets, which are now routinely designed with useful economic lives extending to 30, 35, or potentially 40 years.

2.11.1 Ofgem has consulted on extending the TRS beond 25 years but has deferred a decision to gather more evidence.

The "Extension and evolution of a mature asset class" consultation[54] sets out Ofgem's position on the pros and cons of extending the TRS duration beyond 25 years. Ofgem noted challenges related to longer TRS durations including financing being optimised for 25-year periods, and potential impact on consumers if an OFTO decommissioned the assets early, amongst others. Whilst these are legitimate concerns, it seems likely that additional policy measures could resolve or mitigate the impact of these challenges.

54 https://www.ofgem.gov.uk/sites/default/files/2024-12/OFTO_consultation_extension_evolution_mature_asset_class.pdf

From an international perspective, license periods of 25 years are granted in Denmark and Germany, whereas in the Netherlands the initial licence period is 30 years with extensions of up to 10 years. In these jurisdictions the offshore transmission assets are either owned by the generator or the TSO, therefore potential complications caused by the profit motive of the asset owner favouring decommissioning rather than extension are not present (refer to APPENDIX 2 - International perspectives on generator ownership of offshore grid transmission for more information).

2.11.2 Allowing TRS periods of longer than 25 years would potentially resolve or at least defer many of the challenges currently being faced.

Allowing TRS periods of longer than 25 years would potentially resolve or at least delay many of the challenges currently being faced by projects seeking an extension at the end of their existing TRS. For example, allowing 30- or 35-year TRS periods would reduce the impact (in terms of number of years of "lost" generation) of assets being decommissioned unnecessarily after 25 years due to failure to agree on ERS extension.

2.11.3 Ofgem should continue to gather evidence and publish a timeline for a decision.

Given that policy changes on TRS duration cannot be implemented retrospectively it is important that Ofgem does not allow unnecessary delay in reaching a decision on whether it would be appropriate to extend the TRS duration. Given that the pressure to allow longer TRS durations is only likely to grow as expected asset life increases with technological maturity, it would be beneficial for Ofgem to set out an indicative timeline for gathering evidence and making a decision on whether to extend the TRS duration.

Recommendations for the Future OFTO Regime

3.

3.1 Recommendation 12:

The OFTO regime must change to accommodate the extended commissioning timeline of floating offshore wind projects.

Ofgem should consider how the OFTO regime will interface with large floating offshore wind projects which may face particular challenges under a regime designed for fixed bottom technology. Floating offshore wind represents a significant evolution in offshore wind technology that will require adaptation of many aspects of offshore wind policy, including the OFTO regime.

3.1.1 The OFTO tender process and GCC has evolved to meet the needs of fixed bottom projects, however floating projects have much longer commissioning timelines which could be challenging for OFTOs.

Large floating offshore wind projects face significantly longer commissioning periods than fixed-bottom installations, typically 3 to 4 years, and potentially up to 5 years when accounting for adverse weather impacts. This extended timeline is driven by differences in the technology and supply chain maturity, and the unique logistics requirements of floating offshore wind projects. The availability of suitable port infrastructure and installation vessels limits the rate at which floating turbines can be manufactured, staged, and deployed. Whilst there is significant activity to expand port capacity, current limitations necessitate extended commissioning timelines. For example, a 400 MW project is unlikely to be fully installed within a single season, whilst larger projects such as 1.35 GW developments may require 3 - 4 seasons simply to deploy the turbines.

The OFTO tender process has evolved to meet the operational requirements of fixed-bottom projects and needs to adapt to meet the needs of floating projects. For example, the OFTO preferred bidder stage usually takes place once assets are already fully energised; demonstrating that transmission assets can operate at full capacity becomes substantially more difficult when the connected wind farm is commissioned over multiple years, complicating the due diligence and handover process to the OFTO.

3.1.2 For large floating offshore wind projects, there may be reduced appetite from OFTOs given the increased risks, as well as increased cost to consumer resulting from indemnities and higher insurance costs.

The inability to test transmission assets at full capacity during the preferred bidder stage introduces uncertainty regarding asset performance and design validation. OFTOs' appetite to bid for such projects may be reduced if they must accept the risk that the transmission system cannot be tested at full capacity until several years after the transaction completes, or they may require higher risk premiums for these projects.

OFTOs may seek additional indemnities and warranties from developers to mitigate these risks, these additional costs will ultimately be passed through to consumers, either directly through higher TRS payments or indirectly through the CfD strike price as generators factor in anticipated OFTO risk premiums.

There is also a risk that floating projects may artificially reduce their scale to manage OFTO risk appetite, thereby failing to capture economies of scale.

3.1.3 Ofgem and DESNZ should consider how the OFTO transaction process should be adapted to provide greater flexibility for floating offshore wind projects.

The challenges outlined above indicate that the OFTO regime requires adaptation to accommodate floating offshore wind without imposing unreasonable costs or risks on OFTOs, developers, or consumers. In particular the OFTO tender process and GCC framework needs to accommodate the extended and phased nature of floating wind deployment and commissioning. Whilst the transmission infrastructure is conventional, the technology it connects has very different installation and commissioning constraints to fixed bottom projects.

3.2 Recommendation 13:

A workable OFTO Build policy, including Ofgem proposals for centralised OFTO Build tenders, would provide a solution to many of the challenges presented in this report.

Under an OFTO Build approach, the OFTO would assume responsibility for financing, design, construction and operation of transmission assets. For more information on the benefits of OFTO Build refer to the Offshore Wind Industry Council (OWIC) report Delivering the shared offshore network and Ofgem's OFTO Build consultation[55] published September 2025.

3.2.1 Challenges related to the Generator Commissioning Clause, Cost Assessment, and Design and Coordination could be solved with a workable OFTO Build model.

The challenges identified throughout this report which could be addressed through a properly designed OFTO build model include:

Generator Commissioning Clause and unrecovered generator-build financing costs
The current 27-month GCC deadline creates intense commercial pressure for developers during the preferred bidder stage, often compelling them to accept unfavourable terms, indemnities, and warranties to avoid breach of license exemption obligations. Pre-and post-construction financing costs are typically dis-allowed. Under OFTO Build there would be no GCC, and no transmission asset financing costs, and so generators would no longer face these challenges. The challenges related to extended commissioning windows for large floating offshore wind projects not aligning with the GCC timeline and OFTOs preference to have the transmission asset tested at full capacity before the transaction would also be resolved.

Cost Assessment
Developers currently face substantial uncertainty regarding Ofgem's Cost Assessment disallowances, which occur long after CfD bids have been submitted. This forces generators to include risk premiums in CfD bids to account for potential disallowances. Under OFTO Build, the Cost Assessment would apply to the OFTO's construction costs rather than the generators', which would remove this source of uncertainty being priced into CfD bids. A pre-requisite of an early competition OFTO Build model is that it would provide generators with some degree of transmission cost certainty prior to the CfD bid.

Design and coordination for non-radial assets
Early competition OFTO Build has the potential to resolve many of the design and co-ordination challenges under the existing generator-build OFTO regime. Ofgem's proposal for a central body to trigger OFTO Build tenders at the point of seabed leasing is particularly interesting since it could enable larger sections of coordinated grid to be built under an OFTO Build contract. By assigning a single entity to develop a wider area of the network this has the potential resolve some of the most challenging aspects of coordination, such as aligning project phasing, standardising technology specifications, and achieving modular build of coordinated grids where asset classification based on the final network topology complicates responsibilities and timeline dependencies for intermediate development phases.

3.2.2 The OFTO Build model could result in many benefits for consumers.

A workable OFTO Build policy could deliver significant benefits for consumers, delivering all of the benefits of co-ordinated offshore transmission infrastructure

55 https://www.ofgem.gov.uk/call-for-input/ofto-build-ways-forward-early-competition-model

recognised by Ofgem and industry stakeholders set out in the September 2025 OFTO Build Call for Input[56], as well as resolving many of challenges that faced by the generator-build model as transmission assets become more complex and expensive, and helping to enable floating offshore wind at scale.

3.2.3 Further policy considerations for OFTO Build include CfD alignment and the role of generator consortia.

Ofgem has identified the key policy design choices that are necessary to make an OFTO Build model viable, namely: protection of generators from transmission delivery delays so that generators are willing to defer responsibility for construction to an OFTO, non-price tender criteria to attract bidders with the competency to deliver complex offshore infrastructure, and alignment with the Centralised Strategic Network Plan process.

Consideration must also be given to the interaction between the OFTO Build tender process and CfD auctions. Generators require a degree of certainty on TNUoS costs ahead of CfD auction timelines. Depending on the chosen commercial model, the OFTO Build tender process would need to precede CfD rounds. Alternatively, if project cost baselines evolve as construction progresses, consideration will be needed on how cost uncertainty affects generators' ability to bid with confidence in CfD auctions, and what additional risks might be priced in with consequent impacts on consumers. Ofgem's Call for Input discusses the potential for preliminary works payments and other mechanisms to manage cost uncertainty between bid submission and construction commencement, drawing on experience from the CATO framework. Whilst this approach could prove effective in sharing construction risks, the extent to which such mechanisms can be adapted for offshore transmission, and generators' requirements for certainty in CfD auctions, will require further development and stakeholder engagement.

Finally, consideration should be given to whether consortia of generators should be allowed to deliver OFTO build projects. Generators have proven to be highly effective in delivering offshore transmission infrastructure to date, demonstrating strong project management capabilities, technical expertise and an ability to navigate the complexities of offshore construction. Their established supply chains and proven track record in delivering complex infrastructure would be invaluable in an OFTO Build regime. Given the maturity and sophistication of the offshore transmission sector, there may be significant delivery risk in depending primarily on new market entrants to deliver complex infrastructure in GB waters for the first time, particularly given the scale and urgency of the transmission buildout required to meet net zero targets. However, any arrangements involving consortia of generators delivering OFTO build contracts would need robust governance and protections to ensure appropriate separation between generation and transmission businesses under unbundling rules, and to prevent conflicts of interest that could undermine OFTO build delivery incentives and protections against delayed infrastructure delivery.

56 https://www.ofgem.gov.uk/sites/default/files/2025-09/Call-for-Input-OFTO-Build-Ways-Forward-for-an-Early-Competition-Model.pdf

Conclusion

4.

Over the past two decades, the OFTO regime has contributed to establishing Great Britain as a global leader in offshore wind, accelerating project delivery, unlocking low-cost capital, protecting consumers from delays, and enabling developers to recycle capital into new generation.

As the sector matures, however, the context is changing. Projects are larger, farther offshore, and more complex both in terms of technology and coordination; the first OFTOs are approaching the end of their license terms. These shifts are placing pressure on the regime. We acknowledge and welcome the proactive steps already taken by Ofgem and DESNZ to evolve the framework, most notably the work on EoTRS and coordinated offshore networks, the extension of the GCC window, and Ofgem's exploration of a re-imagined OFTO Build model. These are the right signals at the right time and provide a solid foundation on which to build.

This report also sets out the view of generators on how the regime sould now adapt, providing practical, outcome focused recommendations that address today's barriers, anticipate tomorrow's challenges, and which move the sector forwards in a manner which supports Ofgem's and Government's core objectives. Together, these proposals are offered to ensure the OFTO framework continues to deliver value for money while enabling the next wave of investment in offshore wind.

Our proposals are offered in the spirit of open dialogue and collaboration that have helped the offshore wind sector to thrive. We ask that Ofgem and DESNZ consider the proposals set out in this report carefully, and we welcome dialogue and consultation on the proposals that Ofgem and DESNZ consider of merit for potential implementation or further development. We welcome the opportunity to work in partnership with OFTOs, supply chain, NESO, Ofgem, DESNZ and other stakeholders to refine and implement these proposals. Doing so will help ensure that the next twenty years of growth in offshore wind are as successful as the first; and ensure that the OFTO regime remains an enabler to the success of offshore wind in Great Britain, and does not become a bottleneck to the investment needed to realise the UK's ambition for a plentiful, secure, low-carbon energy system which powers economic growth and minimises cost to consumers.

5. Appendix 1 — International Perspectives on Life Extension for OWF and Transmission

5.1 Denmark

Danish Energy Agency (DEA) granted several extensions to offshore wind farms in 2025. Three descriptive examples of projects are included below:

- A 10-year extension license to Wind Estate for its Samsø wind farm of 23 MW which was commissioned in 2002 with decommissioning initially planned for 2027. The operator had to submit an independent analysis of the remaining service life to support DEA's decision.[57] This is a nearshore wind farm with turbine array cables (medium voltage) connected directly to the onshore substation of Energinet (Danish TSO). The license thus covers both the wind farm and the cables to shore.

- A 10-year extension license to Ørsted for its for Nysted wind farm in 2025, originally licensed to operate for 25 years with an expiry in 2028. The lifetime extension has been granted on the basis that it does not involve replacement of any parts, and no technical or operational changes. The wind farm was constructed in 2003 with a total capacity of 165.6 MW. To grant the extension DEA required an independent analysis of remaining technical life and an elaborate environmental impact assessment. The operators must conduct annual extended service inspections.[58] The offshore 132 kV cables (~10km distance from shore) and substation are owned by Energinet.[59] While there is no explicit mentioning, it is reasonable to assume that their lifetime has been extended accordingly with the wind farm extension.

- A 25-year extension license to HOFOR for its Middelgrunden wind farm built in 2000. As for the above projects, an impartial analysis and investigation of technical conditions and the obligation to carry out annual service inspections are the basis for the extension.[60] Similar to Samsø wind farm, Middelgrunden is a near-shore project with array cables connecting directly into an onshore substation.

In summary, the process for the extension is currently case-specific. Yet, in all cases DEA, the responsible agency, requires an independent analysis of the technical conditions and an EIA report to be performed by the generator to get a right to continue the operations. The extension license for the grid is granted either automatically with the wind farm (where the same company owns the generator and the connection to shore) or is arranged in parallel for the TSO who owns the offshore grid.

5.2 Germany

The oldest among German wind farms will begin to expire around 2040, after 25 years of operation. According to the original regulations, they would have to be fully decommissioned. The German Association of Energy and Water Industries (BDEW) has published a study by Fraunhofer IWES examining scenarios for extending the lifetime and re-use of offshore wind farms and grid connection systems.[61] The Fraunhofer IWES study analysed various scenarios for further operation and reuse, covering factors such as operating and investment costs, failure rates, decommissioning and downtime, and the availability of vessels and supply chains. The results of the study showed that coordinated extension of the operation of installations by another 10 years, followed by dismantling and construction of new ones, can increase electricity production in the cluster while reducing overall costs to the economy compared to a scenario where farms are directly decommissioned and replaced after 25 years[62].

The Government will need to develop a supporting regulatory framework to govern the lifetime extension procedure. In Germany the ownership of the wind farm and offshore transmission is split between the generator and the TSO, respectively. Hence, the future framework will have to address both assets explicitly.

57 https://www.offshorewind.biz/2025/06/03/samso-offshore-wind-farm-to-operate-longer-as-denmark-issues-first-extension-permit/

58 https://www.windpowermonthly.com/article/1923600/denmark-grants-lifetime-extensions-its-two-oldest-offshore-wind-farms ; https://ens.dk/media/6700/download

59 https://bogf.eu/wp-content/uploads/transfer/6_LightingRound_Denmark.pdf ; https://www.nordicenergy.org/wp-content/uploads/2012/01/nordvind_finalreport_16_11_2010.pdf ; https://web.archive.org/web/20120610093349/http://www.dongenergy.com/SiteCollectionDocuments/NEW%20Corporate/Nysted/WEB_NYSTED_UK.pdf

60 https://www.offshorewind.biz/2025/06/27/25-year-old-danish-offshore-wind-farm-gets-approval-to-operate-for-25-more-years/

61 https://balticwind.eu/bdew-extending-the-operating-life-of-wind-farms-to-35-years-is-economically-and-environmentally-beneficial/

62 https://www.bdew.de/media/documents/20250924_BDEW_Fraunhofer_IWES_Evaluation_Weiterbetriebs_Nachnutzungsszenarien__h9kWzJ4.pdf

6.3 The Netherlands

In the Netherlands wind farms are given a 30-year license for operation, including a maximum of 5 years for construction.

5.3.1 Actual experience

Egmond aan Zee, the oldest offshore wind farm in Dutch waters, was commissioned in 2007 and was given a permit to operate for 20 years. As the technical inspection has shown that the wind turbines can continue to be operated longer, the owner (Shell) applied for a 5-year extension of its permits. The necessary permits were obtained to remain operational through 2031.[63] This involved the review of the original permits, a new environmental permit, a technical investigation by an independent party and an ecological study (an EIA). The wind turbines are connected into strings of 36 kV which are routed directly to the onshore substation, there is no offshore substation. The cables are owned by the wind farm owner, hence the granted extension applies equally to the grid and to the generation assets.

5.3.2 Framework for the future projects

The entry into force of the amended Offshore Wind Energy Act on 29 October 2021 stipulated the maximum permit period for offshore wind farms to change from 30 years to 40 years. In addition, wind farm permit holders already awarded a permit with a term less than 40 years can apply for an extension of the permit.[64]

The future offshore wind projects will entail a dedicated offshore grid connection, consisting of the offshore substation platform offshore cable connection and the onshore substation. The offshore grid for each project is owned by the TSO TenneT.

- For wind farms yet to be granted a permit - the Dutch regulator has assigned a 30-year depreciation period for the future offshore grid. It has required TenneT to take a possible service life extension of up to 10 years into account as efficiently as possible (thus for a total of 40 years) for the future projects. It is not publicly known how this decision affects TenneT's O&M strategy, how its allowed OPEX costs for servicing the offshore grid (typically set for the 5-year duration of the regulatory period and regularly reviewed)[65] are changed, and how the upfront CAPEX allowance is affected.
- For the existing projects where a permit has already been granted and the relevant parts of the grid are already in use or at an advanced stage of development – an extension covering the full ten years in advance does not always appear to be the best option. It may be that a shorter extension is more in line with the technical service life of some wind farms and would make it easier for TenneT to extend the service life of the offshore grid in a cost-efficient manner. Ultimately, suitable extension periods will therefore have to be decided on a case-by-case basis for each requested extension, taking into account all interests. Development Framework stipulates that the minimum lifespan of the offshore grid is 37 years for wind farms issued a permit under the amended Offshore Wind Energy Act, starting with the future wind farms.

To summarise, for the older projects, the process of lifetime extension has been performed on the basis of the review of the original permits, an independent technical investigation, and an additional EIA where required by an updated or new law. For the future extension decision, the regulator and the agency responsible for the development of the offshore wind in the Netherlands, the preference is given to taking the decisions on a case-by-case basis through a consultation between the generator, the agency, and the TSO. An extension for up to 40-year lifetime can be granted for both the wind farm and the offshore grid.

63 https://ponderaconsult.com/en/news/lifetime-extension-of-5-years-for-wind-farm-egmond-aan-zee

64 https://english.rvo.nl/sites/default/files/2025-02/Development-Framework-Offshore-Energy-v3-February-2025.pdf, p 33

65 https://www.acm.nl/sites/default/files/documents/dnv-gl-study-on-estimation-method-for-additional-efficient-offshore-grid-opex.pdf

6. Appendix 2 — International Perspectives on Generator Ownership of the Offshore Grid

In general, European Commission approves offshore grid ownership by the generator and treats the simultaneous participation in transmission activities and in production/supply activities as compatible with the unbundling rules as long as it can be proven that it does not give rise to any potential conflict of interest, limited third-party access to the grid, or additional costs to the consumers.[66] Given that the radial offshore transmission grids are designed to be used by a single generator, and expansions are not foreseen, it is not possible for the offshore grid owner to limit the competition as such.

Two specific country cases are reviewed below.

6.1 Denmark

Overall offshore wind framework

In the past Denmark operated two mechanisms for offshore wind farm development – an open-door procedure and a tender-based process.

- In the open-door procedure the project developer takes the initiative to establish an offshore wind farm in a particular area. This is done by submitting an unsolicited application for a license to carry out preliminary investigations in the given area, outside areas that already are designated wind power areas found in the spatial planning process.
- In contrast, in the tender-based process, generators compete in a tender for the development of the project in a designated area.

Under the open-door concessions and old near shore (up to a few km from shore) concessions the generator finances the grid connection up to the nearest onshore transformer station.[67] The generator must pay for grid connection to the nearest onshore transformer station. From that point, costs will be carried by electricity consumers as part of the Public Service Obligation (PSO) fee. The reason for this is that it is unknown until after the tender, how large the wind farm will be or in which areas they will be constructed. In this case it is better to let the grid connection be a part of the project and let the planning and the cost of grid connection and transformer substations be covered by the concessionaire.[68]

For the tender-based large offshore wind farm projects the grid connections are planned, procured, installed, operated and paid for by the TSO.

Offshore grid ownership by the generator – Thor project

One exception to the currently operating tender-based TSO ownership regime, where the TSO Energinet plans and develops the offshore grid, is 1 GW Thor wind farm, where the offshore grid connecting the wind farm to the onshore substation fell within the responsibility of the generator. Additionally, the generator was responsible for financing (but not the construction, operation and ownership) of the onshore grid reinforcement.[69]

The license granted to the generator is described in the official documents as "the licence to construct the electricity production plant and associated internal collection grid". Thus, despite the high voltage of the offshore connection, the grid is classified as an internal collection grid and was initially excluded from the "unbundling law" under the premise that equal and non-discriminatory third-party access to the transmission grid in line with EU regulations is ensured.[70]

At the same time DEA included Reservations for unbundling regulations in its draft concession agreement.[71] Thereby:

"If the Danish Energy Agency considers it necessary, including in order to comply with the EU regulations on equal and non-discriminatory third party access to the transmission grid, the Danish Energy Agency is entitled, at any time, including in a possible extension of the concession period, but prior to issuance of an approval for dismantling the installation, to appoint a transmissions system operator (Energinet) to take over the cables routing onshore and the nearshore substation onshore without payment or compensation to the Concessionaire apart from all direct costs in connection with the transfer, including costs of technical changes to existing facilities (transfer of the POC to the offshore substation) caused by the transfer to Energinet, as well as eventual costs related to early termination of contracts for operations and maintenance of the export cables and related onshore substation. The TSO will not be entitled to collect separate tariffs, in addition to the general tariffs, for transmission by the Concessionaire of electricity from Thor Offshore Wind Farm to the collective electricity supply grid in connection with Energinet acquiring ownership of the cables routing onshore with the associated nearshore substation onshore."

In practice, the above text caters for an unlikely hypothetical scenario where a third party will wish to connect to the offshore grid infrastructure that serve the Thor wind farm.

Currently, the project is under construction by RWE and is scheduled for commissioning in 2027.[72]

66 https://www.clearymawatch.com/2016/02/investing-in-energy-in-the-eu-navigating-the-ownership-unbundling-rules/#_ftn3

67 https://ens.dk/sites/default/files/media/documents/2024-11/offshore_wind_development_0.pdf p28

68 https://ens.dk/sites/default/files/media/documents/2024-11/offshore_wind_development_0.pdf p 25

69 https://www.google.com/url?sa=i&url=https%3A%2F%2Fwww.ethics.dk%2Fethics%2FpublicTenderDoc%2Fbfb4d610-bfa1-4bfe-8808-6deb212e27cb%2Fddf8890d-a5f0-4070-a8f4-5ddda1b01c09%2Fdownload&psig=AOvVaw0Mlg8snCdIGOZ3LORuzdW&ust=1759405287613000&source=images&cd=vfe&opi=89978449&ved=0CBkQ3YkBahcKEwj42PnS9YKQAxUAAAAAHQAAAAAQCw

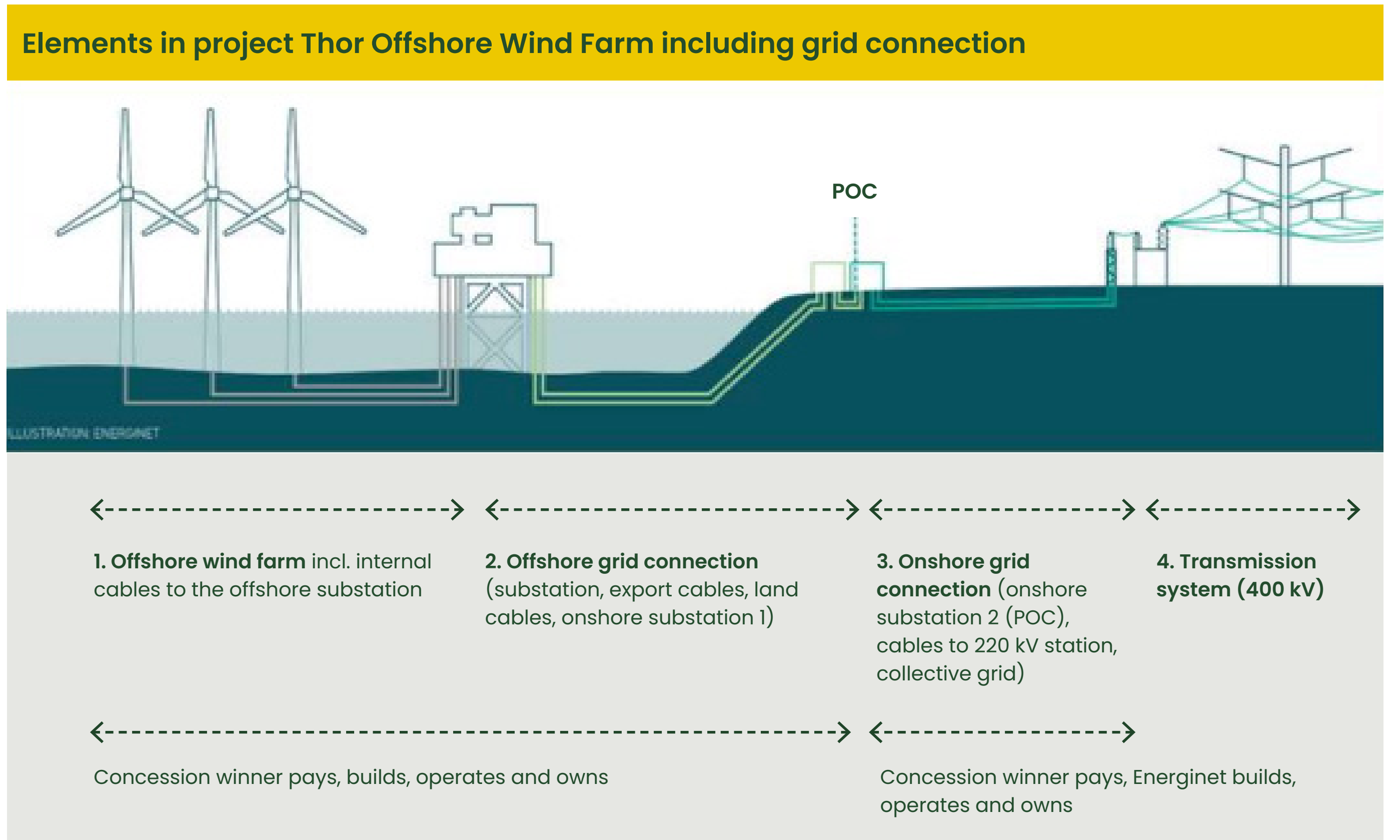
70 https://ec.europa.eu/competition/state_aid/cases1/202111/291899_2254450_111_2.pdf

71 https://www.ethics.dk/ethics/eo#/bfb4d610-bfa1-4bfe-8808-6deb212e27cb/publicMaterial Article 21 in Annex 3

72 https://thor.rwe.com/project-information

73 https://www.4coffshore.com/news/energinet-submits-thor-eia-nid21422.html

Figure 6 Asset ownership split for Thor offshore wind farm[73]



6.2 Poland

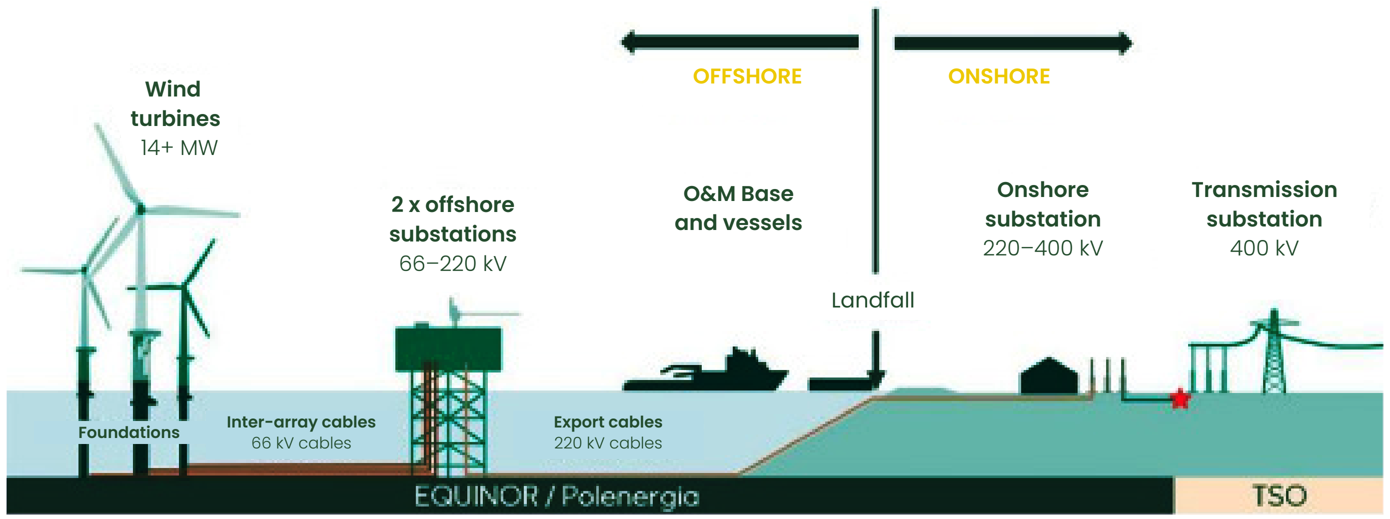
There is only one TSO in Poland – Polskie Sieci Elektroenergetyczne S.A. (PSE S.A.) responsible for the whole 220 and 400 kV grid in Poland. Offshore farms will be connected to this grid. The generator is responsible for the preparation of the construction design, obtaining all necessary permits, construction and operation of the offshore grid (offshore substation, subsea cable and onshore substation if necessary). The boundary of responsibility of TSO and the generator is the connection point at TSO's onshore substation.

Articles 58-60 of the Polish Offshore Wind Act define the procedure for the sale of (parts of) the offshore grid. The process can be initiated equally by the generator and by the TSO. The regulator oversees the negotiations and sets the price based on the "replacement cost" method. One of the reasons for the potential sale mentioned in the Act is "the purchase of the power transmission equipment is necessary for the TSO to carry out a strategic investment and is justified in order to balance the interests of energy companies and energy consumers". This means, that where the overarching energy system development needs require it, the generator may be forced to sell its part of the offshore grid to the TSO, in which case it will become a part of the national transmission system. Until then, it remains classified as a part of the wind farm park.

It is notable that no offshore wind farm has started operation in Poland yet. The above regulations may be amended or extended in the future. At the moment of writing this report, none of the official documents explicitly refers to the rules of unbundling. Therefore, Poland, in its decision to follow generator-own approach for the offshore grid, likely refers to a similar rationale as Denmark – for as long as the ownership of the offshore transmission grid by the generator allows for an equal and non-discriminatory third-party access to the transmission grid in line with the EU regulations, the generator may be the owner.

74 https://baltyk123.pl/wp-content/uploads/nts-eng-1.pdf

Figure 7 Example asset ownership split diagram for Polish offshore wind projects Baltyk 2&3[74]



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