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Guidance

Offshore Transmission: Guidance for Cost Assessment (2022)

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Overview

Under the regulatory regime for the construction and operation of offshore Transmission Assets, Ofgem runs a competitive tender process to select and license Offshore Transmission Owners. To facilitate the tender process, Ofgem undertakes a cost assessment of the offshore Transmission Assets developed and/or constructed before they are transferred to the appointed OFTOs.

This guidance document sets out the cost assessment process that we follow to determine the transfer value for offshore electricity transmission projects developed and constructed by developers. It describes our approach for determining the economic and efficient costs of offshore Transmission Assets and provides developers with an overview of the information we require.

This guidance has been written taking into account best practices and lessons learnt since the previous version of this document (published in 2019) and experiences in executing offshore project assessments up to, and including, Tender Round (TR) 6.

Contents

Executive Summary

The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 (the **Tender Regulations**) govern how the Authority runs the Tender Process and grants offshore electricity transmission licences to offshore transmission owners (**OFTOs**). This process includes assessing the economic and efficient costs of developing and constructing offshore Transmission Assets.

OFTO projects are constantly evolving, driven by:

- new technologies, which enable increased productivity and allow developers to build projects larger and farther offshore;
- market conditions which fluctuate in response to energy demand and supply; and
- regulatory updates such as the application of TNUoS to interlinks.

This guidance document has been updated to align the cost assessment process with the evolution of the OFTO market and to reflect Ofgem's further experience in completing cost assessments.

Ofgem has produced this document to inform all interested parties of the Authority's approach to cost assessment for offshore transmission. We have previously published Cost Assessment Guidance (**CAG**) in 2012, 2017 and 2019[1] and much of the guidance contained in this document was also covered in the previous CAGs. The main changes in approach are in relation to the following areas:

- Final Transfer Value (FTV) (see paragraph 2.17);
- Allocation methodology (see paragraphs 3.5 to 3.13;
- Direct costs for Transmission Assets (see paragraphs 3.15 to 3.18);
- Project management costs (see paragraphs 3.23 to 3.25);
- Off Shore Platfom (**OSP**) assets supporting generation activities (e.g. Helidecks, array switchgear) (see paragraph 3.29);
- Onshore substation areas supporting generation activities (see paragraph 3.30);
- Fibre optic cables for generation related activities (see paragraphs 3.31 to 3.32);
- Land costs (see paragraphs 3.46 to 3.47);
- Hedging of exchange rates (see paragraphs 3.54 to 3.61);
- Generator Focused Anticipatory Investment (see paragraphs 3.72 to 3.75);

[1] "Offshore Transmission: Guidance for Cost Assessment" Ofgem, 2012, "Offshore Transmission: Updated Guidance for Cost Assessment" Ofgem, 2017 and "Offshore Transmission: Guidance for Cost Assessment (2019)" Ofgem, 2019.

- Ancillary Services (see paragraph 3.76);
- Exceptional Events (see paragraph 3.77); and
- Allocation and assessment of interest during construction (**IDC**) (see paragraphs 3.91 to 3.103).

This guidance document has been produced to assist developers in their understanding of the offshore transmission cost assessment process, the key issues that have arisen to date and the Authority's approach to such issues.

This guidance is relevant to both ongoing and future cost assessments. We intend to keep this guidance and our approach to cost assessment under review to ensure alignment with policy developments in the offshore regime and to deal with project specific issues as they arise. We will continue to engage with stakeholders and consult as appropriate to ensure the regime remains fit for purpose.

1. Introduction

Context and related publications

1.1. In 2009, the Government introduced the regulatory regime for offshore electricity transmission to connect significant amounts of renewable offshore generation to the onshore electricity network (the **OFTO regime**).

1.2. OFTOs are appointed through a competitive tender process (the **Tender Process**). OFTOs are granted an offshore transmission licence (**OFTO Licence**) with a fixed revenue stream for a specified time.

1.3. From the outset the OFTO regime has encouraged innovation and attracted new sources of technical expertise and finance, whilst ensuring that grid connections are delivered efficiently and effectively.

1.4. The Tender Regulations govern the Tender Process and provide that the Authority must calculate the economic and efficient costs of developing and constructing offshore Transmission Assets.[2]

1.5. Where the Authority has granted an OFTO Licence to a Successful Bidder, for a particular project, the value of the assets transferred to the OFTO is determined based on the cost assessment carried out by Ofgem. This transfer value is reflected in the revenue stream of the OFTO Licence.

Associated documents

1. The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015
2. Offshore Transmission: Tender Process Guidance Document

[2] See below at paragraphs 2.1 to 2.5 for further details.

2. The Cost Assessment Process

Section summary

This section sets out the context for cost assessment within the regulatory regime for offshore transmission and the cost assessment process adopted for "Generator Build" projects i.e. those developed and constructed by developers.

The purpose of offshore transmission cost assessment

2.1. As part of the OFTO regime, Ofgem runs the Tender Process in accordance with the requirements of the Tender Regulations. The Tender Process results in the identification of an offshore transmission owner and operator (the OFTO) to whom the Authority grants a licence for offshore electricity transmission (the OFTO Licence).

2.2. The Tender Regulations require the Authority to determine the value of the Transmission Assets to be transferred to the OFTO (the **Transmission Assets**), by calculating the "**economic and efficient costs**" [3] which ought to be, or ought to have been, incurred in connection with developing and constructing the Transmission Assets for a Qualifying Project. Prior to the transmission of electricity, this calculation will take the form of an "estimate" of costs and as soon as reasonably practicable after the estimate and once the Authority is satisfied that the Transmission Assets are available and has the information required, an "assessment" of costs.[4]

Regime overview

2.3. Developers may choose to either:

- develop and construct the Transmission Assets themselves and then transfer the completed Transmission Assets to the OFTO identified through the Tender Exercise (the **Generator Build** option); or

- undertake high-level design and preliminary works, but then defer the detailed design, procurement and delivery of the Transmission Assets to the OFTO (the **OFTO Build** option).

2.4. The cost assessment process for each of these two build options is different. In the case of OFTO Build, it will be based on the economic and efficient costs of obtaining the design and preliminary works, and in the case of Generator Build, it is based on the economic and efficient costs of developing and constructing the Transmission Assets.

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[3] Regulation 4(1) (Calculation of costs incurred in connection with Transmission Assets) of the Tender Regulations.
[4] Regulation 4(2) of the Tender Regulations.

However, the principles applied to assess the relevant economic and efficient costs are similar.

2.5. As all developers have so far utilised the Generator Build option, this guidance document is focused only on the cost assessment process for the Generator Build model.

Purpose of this document

2.6. The Tender Regulations do not stipulate how the Authority should calculate the economic and efficient costs of developing and constructing the Transmission Assets.

2.7. The purpose of this guidance document is to inform developers, and other interested parties, of the Authority's approach to offshore transmission cost assessment. As Ofgem completes more cost assessments, and to keep up with any regulatory updates, we may consider it appropriate to update this guidance to improve the cost assessment process for all stakeholders. We will continue to explore ways in which the regime can be improved, in consultation with stakeholders.

Stages of the offshore transmission cost assessment process

2.8. The developer-facing cost assessment process is conducted by the Authority, in parallel with the Bidder-facing side of the Tender Process. Below, we summarise the stages involved in the cost assessment process and the points of interaction with the bid side of the Tender Process. A tabular illustration of the alignment between processes is contained in Appendix 1 to this guidance.

Initial Transfer Value (InTV)

2.9. To support the start of a Tender Exercise and as the first stage in the cost assessment process, we set the Initial Transfer Value (**InTV**). This is not the "estimate" of costs required under the Tender Regulations, but the developer's initial estimate of how much it will cost to build the Transmission Assets. We provide the developer with a pro forma cost assessment template (**CAT**) in which to submit this cost information (see Appendix 2 for a detailed summary of the information required to be provided in the CAT). The CAT is broken down into the following cost categories:

- offshore substation(s)
- submarine cable (incl. any interlinks)
- onshore cable
- onshore substation
- reactive substation(s)
- connection
- other
- transaction

2.10. We would usually perform a basic review including benchmarking of the cost information at this stage and indicate to the developer any issues that would require more in-depth scrutiny at later stages.

2.11. We publish the InTV in the preliminary information memorandum at the Enhanced Pre-Qualification (**EPQ**) stage of the Tender Exercise. The purpose of the EPQ stage is to identify a suitable shortlist of Bidders to proceed to the Invitation to Tender (**ITT**) Stage.[5]

Indicative Transfer Value (ITV)

2.12. The next stage of the cost assessment process is setting the Indicative Transfer Value (**ITV**). This is the "estimate" of costs which ought to be incurred, or have been incurred. At this stage, the developer submits updated cost information upon which Ofgem, with the support of its advisers, carries out a forensic accounting review and, if required, a technical review.

2.13. The accounting exercise entails a review of the developer's contracts for the development and construction of the Transmission Assets. The contracts are checked against the details provided at the InTV stage, and the proposed cost allocations between the Generation Assets (which are excluded from the cost assessment) and the Transmission Assets is reviewed.

2.14. The technical review typically focusses on two aspects:

- **Project design:**
    - Reviewing the overall design of the Transmission Assets, including features such as the choice of electrical design, procurement efficiency, risk logs and the technology options evaluated.
    - The main purpose is to ensure the project design is functionally appropriate for the connected generation. If the project design is considered inefficient, we will discuss our concerns with the developer, to inform our consideration of whether the costs for the Transmission Assets can be considered economic and efficient.
- **Economic and efficient costs:**
    - Considering whether the costs for the Transmission Assets are economic and efficient.
    - We do this by comparing the developer's cost submissions with costs from other transmission projects Ofgem has assessed (making allowances for project specific elements), and the cost data held by our advisers. Following identification of any cost anomalies, we discuss the reasons for these differences with the developer, to inform our consideration of whether costs have been incurred in an economic and efficient manner.

2.15. The ITV is published at the start of the ITT Stage of the Tender Process. The outcome of the ITT Stage is the identification of the Preferred Bidder for the Qualifying

[5] For further details on the stages of the Tender Process, see the latest Tender Process Guidance Document (**TPGD**).

Project. Subject to satisfaction of certain matters prescribed in the Tender Regulations, the Preferred Bidder will become the Successful Bidder and ultimately the OFTO. Qualifying Bidders at the ITT Stage use the ITV as an assumption for the tender revenue stream (**Tender Revenue Stream** or **TRS**), which they bid to own and operate the Transmission Assets.

2.16. Costs set at the ITV may be revisited at the Final Transfer Value (**FTV**) stage. Unless we explicitly state that a cost item is closed, developers should be prepared to provide further justification for costs during discussions to set the FTV.

Final Transfer Value (FTV)

2.17. The next stage of the cost assessment process is setting the FTV. This is the 'assessment', referred to in the Tender Regulations, of the costs incurred for developing and constructing the Transmission Assets. It is the amount to be paid to the developer by the OFTO for the Transmission Assets. The trigger point for commencing this assessment is when circa 90–95% of the project costs have been incurred. At this point, there is sufficient cost certainty for Ofgem to make a robust assessment of whether such costs are economic and efficient. If we were to delay the assessment process until all project spend had been incurred, the process to transfer of the Transmission Assets and grant of the OFTO Licence would be unnecessarily delayed.

2.18. Delaying the assessment may also cause issues with the assets not being divested before the 18 month Generator Commissioning Clause (**GCC**).[6] Once the Authority is satisfied that this trigger point has been reached and after the estimate has been completed, the Authority will, as soon as reasonably practicable and when it has the information required, commence with the assessment of costs process.

2.19. As with establishing the ITV, Ofgem may, as required, instruct both accounting and/or technical advisers to support this stage of the cost assessment process.

The accounting analysis focusses on:

- checking that the contracts presented by the developer at the ITV stage have been performed; and
- examining the developer's bank statements in order to reconcile stated contract costs with actual payments.

The technical analysis focusses on:

- reviewing areas of significant cost increases since Ofgem set the ITV;
- cost issues not finalised during the ITV stage; and

[6] Decision on implementation of the Generator Commissioning Clause in the Energy Act 2013 https://www.ofgem.gov.uk/publications/decision-implementation-generator-commissioning-clause-energy-act-2013

- examining where comparative analysis has indicated some costs to be outside their expected range.

2.20. Following this assessment, Ofgem sends the developer a draft cost assessment report, setting out the assessed transfer value (the FTV) of the Transmission Assets. This gives the developer the opportunity to correct factual errors and propose redaction of any commercially confidential information. The draft report is also sent to the Preferred Bidder, so that they can factor the assessed transfer value into their TRS calculations. The tender revenue stream amount, incorporating the assessed transfer value, is then published in a consultation pursuant to section 8A of the Electricity Act, by which the Authority proposes modifications to the standard conditions of the OFTO Licence on a project-specific basis (the **Section 8A Consultation**). We refer to this as the "**s8A TRS**", which is adjusted at licence grant to result in a final tender revenue stream amount payable to the OFTO under and in accordance with its OFTO Licence.

2.21. The draft cost assessment report is published alongside the Section 8A Consultation. The report remains in draft form until the Section 8A Consultation has concluded and the Authority has determined to grant the OFTO Licence to the Successful Bidder. After Licence Grant, the final cost assessment report containing the FTV is published on the Ofgem website.

2.22. In each Tender Exercise completed so far, Ofgem has finalised the assessment of costs (the FTV) prior to commencement of the Section 8A Consultation, and the s8A TRS has reflected 100% of the FTV. Where it is not possible to finalise the FTV in time for commencement of the Section 8A Consultation:

- the s8A TRS would instead reflect the ITV and we would use the Post-Tender Revenue Adjustment (**PTRA**)[7] term at Licence Grant to adjust the tender revenue stream to account for 100% of the FTV; or

- if, under exceptional circumstances, this is not possible, we may adjust the TRS to reflect the difference (if any) between the ITV and the FTV upon conclusion of our cost assessment after Licence Grant. Again, we would use a PTRA term after Licence Grant to adjust the tender revenue stream to reflect the FTV.

Timely provision of data throughout the process

2.23. Under the Tender Regulations, the Authority can require a developer to submit further information to assist cost assessment calculations. Where the Authority requests further information, it shall indicate a date by which that information is to be provided. Where a developer fails to submit the information by the required date, the Authority may decide not to take into account the information provided when determining both the ITV and/or the FTV.

[7] The PTRA term is contained in Amended Standard Condition E12-A3 of the generic OFTO Licence. Use of the PTRA term post-Licence Grant would need to be provided for and consulted upon in the Amended Standard Conditions.

3. Cost Assessment Approach

Section summary

In this section, we describe the approach we use for assessing the ITV and FTV of Generator Build projects. We explain how we consider the allocation, accuracy and efficiency of costs components of the following main categories: capital expenditure, other costs, interest during construction (**IDC**) and transaction costs.

Introduction

3.1. The cost assessment process analyses developer cost submissions across four broad cost categories:

- capital expenditure
- other costs
- interest during construction
- transaction costs

3.2. Our assessment considers costs incurred in connection with the development and construction of the Transmission Assets, up to the point at which they are available for the transmission of electricity.

3.3. Below is the description of the cost assessment approach for each of the above cost categories. We also comment on taxation issues at the end of this section.

Capital expenditure (Capex)

What do we mean by Capex?

3.4. The development and construction of the Transmission Assets requires developers to enter into a variety of design, delivery, construction and installation contracts. Typically, the assets that are constructed are offshore platforms, the high voltage electrical power systems on the platforms, subsea export cables, onshore export cables, onshore substations and associated apparatus. We define Capex costs as all the costs involved in the delivery, construction (including civil works), installation and commissioning of assets associated with the project’s transmission system.

Assessment of Capex: allocation and accuracy of costs

3.5. Capex costs must be allocated correctly (i) according to the different costs categories set out in the CAT provided to the developer (see paragraph 3.6 below) and (ii) apportioned between Transmission Assets and Generation Assets in accordance with an allocation methodology established by the developer (see paragraph 3.8 below).

3.6. To assess capital costs at the ITV and FTV stages, we provide the same CAT as at InTV stage, indicating cost categories related to separate elements of the Transmission Assets (see paragraph 2.9 for further details). It is important that costs are attributed correctly to each costs category. Where possible, the developer should allocate costs related to the Transmission Assets as and when they are incurred and according to the relevant asset. This should ensure that costs are attributed directly to each cost category and should reduce the amount of costs related to the project as a whole, sitting in the "other" cost category of the CAT.

3.7. Where components related to the project as a whole are jointly procured, for example cable and cable laying services, Capex costs should be split out between the generation and transmission elements of the project. Where additional costs are incurred on a shared asset (fibre optic cables for example), the developer should identify all additional cost associated with the assets being used for generation purposes and allocate as a Generation Asset. It is important that these costs are apportioned appropriately so that there is no undue cross subsidy of the transmission elements by the generation elements, or vice versa.

3.8. The developer should establish a set of consistent rules for how to allocate costs and follow it for all Capex costs. We would expect that this allocation methodology adopted by a developer, is done on an objective and transparent basis, such that it can be independently replicated and verified. The developer must provide details underpinning its allocation methodology and the metrics that were used to determine what proportion of the costs have been allocated as transmission costs.

3.9. The allocation methodology may be based on metrics such as the relative proportion of direct equipment costs (excluding all shared costs) for the Transmission Assets compared to the project as a whole. Developers may discuss their proposed methodologies and underlying rationale with us ahead of any costs submission. Once any allocation methodology is agreed, we will crosscheck that the allocation of costs accurately reflects the methodology.

3.10. In the event that a developer is unable to provide a metric and has based allocations on an estimate, or we do not consider that a clear, transparent and appropriate allocation methodology has been used, we may:

- allocate these costs based on an estimate of the percentage of Transmission Assets' cost versus the total costs of the project (including both Transmission and Generation Assets); and/or

- decide to either impose a metric or exclude elements of those costs from the transfer value.

3.11. However, in either case we will discuss options with the developer to give them the opportunity to provide substantiation of their estimate(s) or methodology.

3.12. On occasion, the procurement of Generation Assets and Transmission Assets as a package may lead to manufacturing discounts. In such instances, we would expect the discount to be allocated appropriately between the generation and transmission elements of the project. Where discounts are tied across several different projects (e.g. bulk purchase deals), we would expect an objective allocation of the savings across all of those projects so that there is no cross-subsidisation between projects.

3.13. Where insurance policies are procured to cover the project as a whole it will be necessary to identify the cost allocation between the Transmission and Generation Assets. In the absence of any metrics supplied by the developer that are considered appropriate by Ofgem, we may revert to a percentage of Transmission Assets' costs versus the total costs of the project.

Assessment of Capex: efficiency of costs

3.14. In paragraphs 3.15 to 3.77 below, we set out a number of elements which we assess to determine whether the Capex costs are economic and efficient:

- Direct costs for Transmission Assets (paragraphs 3.15 to 3.18);
- Approaches to procurement and contract management (paragraphs 3.19 to 3.22);
- Project Management (**PM**) costs (paragraphs 3.23 to 3.25);
- Treatment of contingency (paragraphs 3.26 to 3.28);
- Offshore substation platform (**OSP**) assets supporting generation activities (paragraph 3.29);
- Onshore substation areas supporting generation activities (paragraph 3.30);
- Fibre optic cables for generation related activities (paragraphs 3.31 to 3.32);
- Cable surveys and risk assessments (paragraphs 3.33 to 3.36);
- Interlinks (paragraphs 3.37 to 3.38);
- Vessels (paragraphs 3.39 to 3.40);
- Spares (paragraphs 3.41 to 3.44);
- Operational faults (paragraph 3.45);
- Land costs (paragraphs 3.46 to 3.47);

- Connection costs (paragraphs 3.48 to 3.49);
- Insurance (paragraphs 3.50 to 3.53);
- Hedging of exchange rates & commodities (paragraphs 3.54 to 3.61);
- Outstanding costs (paragraph 3.62);
- Treatment of cost overruns (paragraphs 3.63 to 3.66);
- Capitalisation of operating costs (paragraph 3.67);
- Depreciation of operational projects (paragraph 3.68);
- Anticipatory and wider network benefit investment (paragraphs 3.69 to 3.75);
- Ancillary services (paragraph 3.76); and
- Exceptional events (paragraph 3.77).

Direct costs for Transmission Assets

3.15. Direct costs are those costs that can be attributed specifically to the various elements of the Transmission Assets (and hence cost categories). To inform our assessment of costs at the ITV and FTV stages, we may look at how the direct costs submitted by the relevant developer compare with industry averages derived from other OFTO projects (**benchmarking analysis**) supported by our technical advisers, where appropriate.

3.16. We use benchmarking analysis to guide our decisions on what cost areas it may be appropriate to investigate further, rather than as an absolute determinant of allowable costs. Where specific costs are highlighted as a concern, we conduct further analysis to determine whether such costs would be or were incurred economically and efficiently.

3.17. Developers are given the opportunity to explain why their costs may differ from those on similar projects. We require detailed explanations for any costs that are unique to that project, or costs that are materially different to those expected. To explain any differences between the benchmark analysis and the developer's submitted costs. We also expect the developer to be able to quantify and evidence any additional project specific costs, so that we can then consider whether those costs are economic and efficient.

3.18. In the absence of appropriate evidence to justify these differences, we may use the benchmarking data to inform our view of whether or not the relevant costs can be considered economic and efficient. Our investigation and analysis are not solely based on the results of our benchmarking work. We may also investigate areas where project costs are benchmarking well.

Approaches to procurement and contract management

3.19. Efficient procurement processes can make a significant contribution to controlling costs. In considering whether costs incurred are economic and efficient, we will review the relevant developer's approach to the procurement and contract management processes of the main items of expenditure for the Transmission Assets. Developers should provide us with appropriate documentation relating to the processes that were followed and a detailed justification of the outcome(s).

3.20. The developers of projects to date have adopted a variety of approaches to contract management. Some have managed through combinations of alliancing, wrapped contracts and the utilisation of their own resources, while others have utilised a turnkey approach. Ofgem does not have any preference as to the approach taken to contract management, but developers should be able to justify that the costs incurred are economic and efficient. As an example, we would expect that turnkey contracts may increase a project's initial cost forecast, but that there would be a commensurate reduction in project risks and associated costs. Furthermore, where developers opt for a wrapped or turnkey contract, they should provide disaggregated cost data to allow us to make meaningful comparisons between the different cost categories. Essentially, this means that we require the developer to provide a breakdown of the total costs associated with the relevant wrapped/turnkey contract allocated to each cost item reported in the CAT.

3.21. We expect developers to manage their contractors effectively. They should provide evidence that project management or contract control processes are put in place upfront (ie before the relevant contract is signed) to minimise any cost overruns. Developers should also be able to evidence how they implement their contract and cost control processes throughout the duration of the project. If a lack of robust contract cost management leads to increased costs in the development and construction of the Transmission Assets, we may conclude that such costs were not economic and efficient and may not, therefore, be included.

3.22. Where developers incur additional costs to complete or rectify works owing to a contractor's failure to deliver (including costs incurred in replacing failing or defaulting contractors), we would expect the developer to seek recompense through the appropriate contract(s) rather than through the cost assessment process. Where such a contractual settlement has been reached, we would expect the developer to be able to explain the rationale for the settlement and clearly identify the assessment of damages, the value proposed by the contractor and the settlement reached, including details of the negotiations and justification of the settlement sum. If contractual settlement terms apply, across both generation and transmission elements, we expect the developer to be able to justify the allocation methodology used. Any sums recovered through such claims may be reflected in an adjustment to the FTV. If claims are not due for settlement at an appropriate point in the cost assessment process (eg prior to the Section 8A Consultation), we would consider reflecting an appropriate amount in the FTV with the appropriate justification.

Project management costs

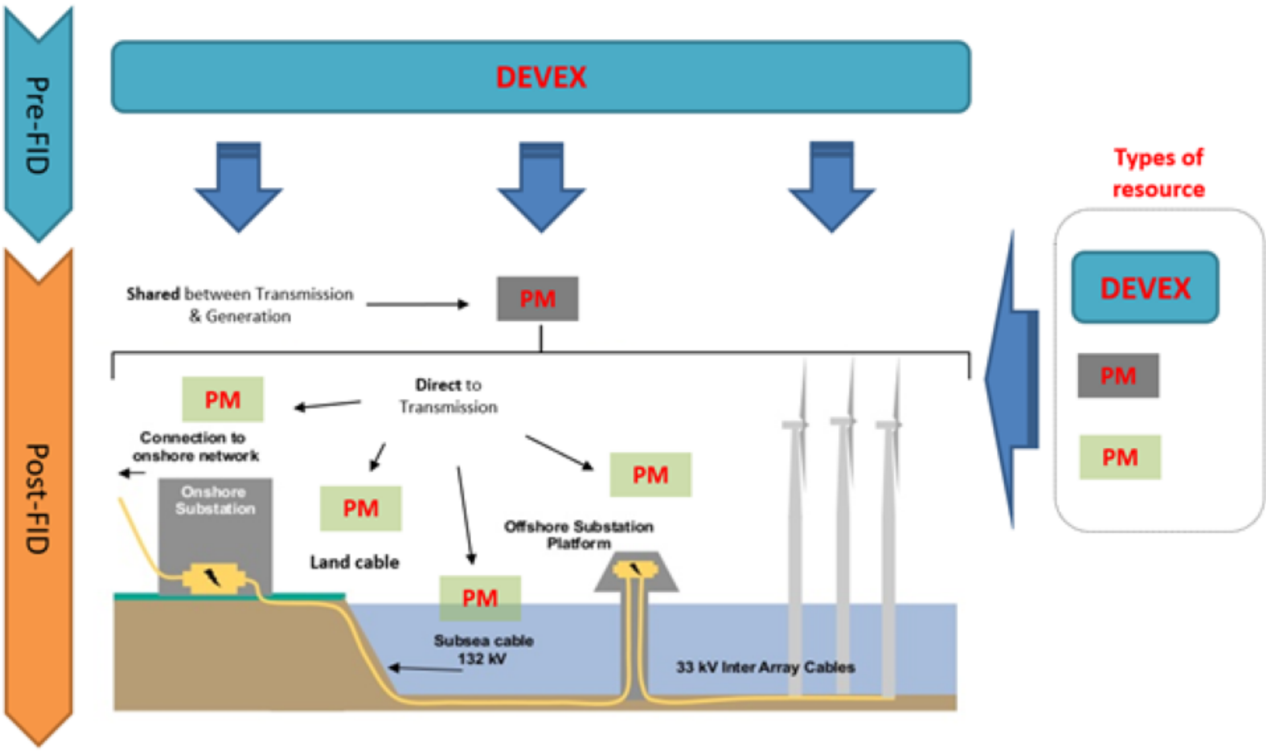
3.23. PM costs can be divided into:

- PM costs directly attributed to each cost category in the CAT (**direct PM costs**); and

- PM costs that relate to the entire project and that will therefore sit within the "other" cost category in the CAT, and will need to be correctly allocated between the Generation Assets and the Transmission Assets (**end-to-end PM costs**).

  Both direct PM costs and end-to-end PM costs will be evaluated during the cost assessment process. Figure 1 illustrates direct PM costs in green and end-to-end PM costs in grey.

Figure 1: Map of resource costs in OFTO projects



3.24. When assessing PM costs we will take into account the characteristics of the specific project. For example, for a project that utilises a multi-contracting strategy, we would not, based on the historical levels seen for past projects, expect direct PM costs to typically exceed 10% of Capex. For each costs category, we will compare direct PM costs against Capex costs (net of direct PM), and calculate the average across all cost categories. End-to-end PM costs are evaluated as part of the Development costs (see below at paragraph 3.79). In a turn-key approach part of the PM costs are included in the developer's contracts and we consider the overall amount of PM costs should be considerably lower when compared to Capex, again, based on our experience of past projects.

3.25. For all internal costs (including PM), developers are required to submit the job titles of personnel involved, the activities that they worked on, their day rates and the number of days (or % age) spent on transmission activities versus the number of days spent on the total project (non-transmission related activities) in order to substantiate any claims for such costs. Any mark-up, margin or profit on such internal resources would not be accepted into the transfer value as the costs included by the developer should be at cost only.

Treatment of contingency

3.26. For projects still in the design or construction period, developers' cost data forecasts for the InTV and/or the ITV have tended to include contingency amounts to deal with future uncertainty over the actual cost and timing of construction. We expect developers to have a methodology in place for establishing this contingency amount and to be in a position to explain this to us. Part of this process would usually involve a review of the relevant project's risk log.

3.27. At the time of setting the FTV, the Transmission Assets should be available for use for the transmission of electricity, and all associated costs should be either settled or agreed with suppliers. We do not allow contingency amounts to form part of the FTV.

3.28. If there are outstanding costs or costs in dispute when we are setting the FTV, we will come to a view (informed by submissions from the developer) as to the appropriate amount of these costs to be allowed in the FTV.

OSP assets supporting generation activities (e.g. Helidecks, array switchgear)

3.29. A developer may request to retain the ownership of some OSP assets, such as helidecks, array switchgear and/or SCADA equipment. We may consider that there is evidence that suggests that the need for certain assets on the OSP is driven by the requirements of the developer rather than the OFTO. Where this is the case we will determine the costs of these assets and the costs associated with their impact on the cost of whole OSP, including the topside, jacket/monopile and any associated foundations. We will come to a view (informed by submissions from the developer) as to the appropriate amount of these costs to be deducted from the ITV/FTV.

Onshore substation areas supporting generation activities

3.30. A developer may retain the ownership of some areas in the onshore substation, such as control rooms, communications racks and/or SCADA equipment. In such cases, we will determine the costs associated with their impact on the cost of whole onshore substation, including the building structure, foundations and wider groundworks for the whole site. We will then deduct a portion of these costs from the ITV and FTV to represent the space occupied by the developer (if the developer has not made an equivalent adjustment). Usually this will be done on a square metre area occupied basis, but will be dealt with on a case-by-case basis.

Fibre optic cables for generation related activities

3.31. Fibre optic cables are installed amongst the onshore and offshore export cables for offshore projects. These are used for both transmission and generation control and monitoring and communication purposes. As projects are now being constructed on a bigger scale and farther offshore, cable lengths are increasing along with the numbers of fibres required. This means that the cost associated with the supply and installation of the fibre optic cables can now be significant.

3.32. As the fibres used for generation purposes are not available to the OFTO and the OFTO gains no benefit from them, we will assess the economic and efficient costs associated with these generation assets. If the developer hasn't done so already, we will make an adjustment for the whole costs associated with supplying and installing these fibres, for both on and offshore cables.

Cable surveys and risk assessments

3.33. A number of projects have experienced cost overruns related to the cable installation process and developers may seek to include such cost overruns in the FTV. The reasons for cost overruns are numerous and relate to, amongst other things: technical difficulties, bad weather and 'waiting on weather' costs. However, an emerging theme in such cases is the extent and quality of seabed surveys and risk assessments undertaken by the developer, or its contractor(s), prior to the cable installation process which can assist with efficient and timely installation. We understand from developers that the information obtained from cable surveys and risk assessments is relied upon in determining which cable laying equipment is used during the installation process.

3.34. We will examine any cable installation cost overruns closely, with support from our advisers, as necessary. A key issue in determining whether these costs are permitted, is to understand the steps and actions taken by the relevant developer to mitigate the likelihood of cost overruns. The question of whether or not to undertake detailed seabed surveys, is a commercial decision for each developer. Where a developer decides not to do so, it is liable for the costs arising from that decision.

3.35. Developers should provide evidence that sufficient pre-installation risk assessment and mitigation procedures are in place, prior to the start of the cable installation works. A submission of the project's risk register would normally form an integral part of the evidence base. If, after investigation, it is shown that costs are attributable to inefficient pre-installation risk assessment procedures or mitigation procedures, then these costs will not be allowed in the ITV or FTV.

3.36. There are currently variations in the approaches and standards used by developers when commissioning geophysical studies, geotechnical investigations and cable route assessments. A publication by the Offshore Wind Programme Board recognised that effective surveys could reduce the risks and costs associated with cable installation.[8] This publication highlights good practice for marine survey activity and we suggest that this is reviewed and followed by developers. This should create greater consistency across the industry and improve standards, which may reduce the level of risk priced in by OFTO bidders. This could also reduce the risk of project delays resulting from insufficient information on cable burial conditions.

Interlinks

3.37. An offshore interlink is a circuit which connects two (or more) offshore substations that are connected to a single common onshore substation. It is held in open standby until there is a transmission fault that limits the developer's ability to export electricity to the onshore substation. It is possible that such an interlink could connect two different

[8] See "Overview of geophysical and geotechnical marine surveys for offshore wind transmission cables in the UK", Offshore Wind Programme Board, September 2015

projects owned by two different OFTOs, though so far, they have all been connecting offshore substations from the same project.

3.38. Following the Authority's approval of the Connection and Use of System Code (**CUSC**) modification Proposal CMP242[9], the costs attributable to the interlink need to be separable from the remainder of the system for transmission network charging purposes. We expect interlinks to be costed up separately from the remainder of the project, with project management, etc., allocated appropriately.

Vessels

3.39. A variety of vessels will be required as part of the works associated with the installation of a project's subsea cables and offshore platforms.

3.40. We expect the developer to choose the appropriate vessels to undertake these works and to be able to provide evidence to us to justify vessel choices, in particular in relation to the selection of jack-up and cable installation vessels. Evidence such as a cost benefit analysis should be provided to justify the inclusion of economic and efficient costs of such vessels.

Spares

3.41. Where spares for the Transmission Assets are transferred to the OFTO, we will include the economic and efficient costs of these assets as part of the FTV. Spares that have been, or are intended to be, transferred to the OFTO will be accounted for as part of the original contract prices and relate to the assets that are installed, for example: cable lengths, joints and substation spares. Developers should consider the procurement of spares early in the project design in order to achieve economic and efficient costs.

3.42. In general, we consider that the length of spare cable required for a subsea cable fault repair should be no more than 1km and, therefore, this is the length of spare cable which we would usually allow as part of the FTV. In cases where the developer considers that a longer length of cable is necessary to conduct a repair, and therefore that a longer length is required to be transferred to the OFTO and included in the FTV, it is the responsibility of the developer to provide this justification according to the specific characteristics of the project. We will consider the case submitted and conduct an *ad hoc* technical evaluation of the spare cable necessary, to establish the minimum length required for a "worst case" scenario repair.

3.43. In the past some developers have requested that spare transformers are included in the FTV. Ofgem has extensively reviewed this request and collected data to substantiate its decision that, in general, spare transformers will not be included in the FTV. Based on up-to-date information on transformer failure rates[10], it is Ofgem's position

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[9] "Connection and Use of System Code (CUSC) CMP242: Charging arrangements for interlinked offshore transmission solutions connecting to a single onshore substation", published on 10 February 2016
[10] https://e-cigre.org/publication/ELT_284_6-transformer-reliability-survey

not to allow spare transformers into the FTV, unless the developer provides significant evidence to substantiate their claim.

3.44. If additional spares are to be transferred to the OFTO, and their costs included in the FTV, we would expect the developer to justify why they are required. For material cost items, this justification may take the form of a cost benefit analysis. developers should have considered a range of alternative suppliers, to enable us to determine whether the cost of any additional spares is economic and efficient.

Operational faults

3.45. During the commissioning stage, the Transmission Assets are subject to various tests. Once energised and commissioned, the assets are considered to be available for the transmission of electricity, and the developer assumes full operational control for the system. A number of projects have experienced faults on the Transmission Assets post energisation and commissioning. In some cases, developers have sought to include the repair and associated costs in the transfer value. However, we will not include any of these costs since the Tender Regulations provide for the recovery of development and construction costs only, not those in connection with operational and maintenance activities.

Land costs

3.46. Offshore transmission systems require an onshore substation and overground/underground cables. Land is required to locate the substation and consents and easements are required for the land cable route. Developers either purchase or lease a plot to locate the substation, and purchase or secure lease agreements for the land cable. Typically, developers also need to compensate land owners for disruption caused by construction activities. We can consider including these costs up to the point of construction being complete, but not beyond that point into the operational period. Developers are advised to confirm their approaches for all of these activities and provide the appropriate documentation.

3.47. Developers have taken differing approaches in respect of the retention of land ownership, following transfer of the Transmission Assets. We do not have any preference as to whether land ownership is transferred with the assets or retained by the developer. However, if it is retained, we would expect the land lease costs, for use during the construction, development and operational periods, to be based on an evidenced (preferably market-based), open and transparent methodology. The duration of the lease costs allowed will match the duration of the TRS for that project only. Any additional lease costs after the TRS ceases will not be included. This principle will also apply to any seabed leases.

Connection costs

3.48. Developers will pay a charge for connecting up to the relevant onshore distribution or transmission network. Developers have had differing approaches to these costs; some have submitted these for inclusion in the transfer value, others have not.

3.49. We will review connection charge submissions on a project-specific basis. For each submission, we require the rationale for either including or excluding any such charges.

Where included, we would also need justification for the level of economic and efficient costs to be included.

Insurance

3.50. We recognise that it is prudent for developers to procure insurance to cover events that may occur during construction. We, therefore, allow the economic and efficient costs of procuring insurance for the construction of the Transmission Assets in the FTV. When determining what is an economic and efficient level of cost, we may compare the cost of insurance, on a specific project, against that which we have seen on comparable projects to date, taking into account market conditions and project specific issues.

3.51. It is the developer's responsibility to ensure that it has adequate and appropriate insurance to recover all costs in the event of an insurable event occurring. Therefore, we do not expect the developer to seek cost recovery through the cost assessment for costs that are either unrecovered or disputed from insurance claims.

3.52. If a claim arises, due to an event that occurred during the construction of the Transmission Assets, insurance deductible costs that are assessed as economic and efficient, will be allowed in the FTV. The cost of insurance deductibles, relating to claims made for incidents that occur after the Transmission Assets are operational, will not be allowed in the FTV.

3.53. In the event of multiple claims, the cost of each deductible will be allowed in the FTV, provided that each of these claims are incurred economically and efficiently and relate to incidents that occurred during the construction period.

Hedging of exchange rates & commodities

3.54. All costs submitted by the developer in the CAT should be in sterling (GBP). Some contracts and resource costs will be in foreign currencies and we recognise that developers will adopt different approaches for paying for these contracts. However, for the purposes of the cost assessment process, we adopt a methodology for converting foreign currency that assumes developers have hedged foreign currencies, irrespective of whether they have or not.

3.55. We apply two methodologies: one method at the InTV assessment stage, and a different method at the ITV and FTV assessments. For both methodologies, we use a suitable external reference, such as Bloomberg, for the applicable exchange rate data.

3.56. At the InTV stage, all foreign currency and commodity costs (including any variation orders) are converted either:

3.56.1. using a single exchange rate per currency calculated using a suitable methodology proposed by the developer; or

3.56.2. in the absence of the developer proposing a suitable methodology, using a single exchange rate calculated at a date identified by the developer which corresponds to when the majority of contract payments have been made or will have been made.

3.57. For ITV and FTV assessments, we distinguish between 'firm' and 'uncertain' costs and may apply a different treatment to each, as set out below.

3.58. 'Firm' costs refer to all foreign currency contracts and all foreign currency resource costs foreseen at the date at which the developer made the decision to go ahead with the project and funding was committed (**FID**). For the purposes of determining the ITV and FTV, we assume that developers hedge all contract costs at or near the relevant contract signing date and all firm resource costs at or near FID. We use these dates to calculate a "blended rate" that will be applied to convert all of these costs into GBP. This blended rate is the average of the forward exchange rates corresponding to:

- The dates of significant contract payments, weighted by the volume of these payments; and
- the date profile of resource costs, weighted by the volume of these costs.

Costs incurred before FID will be converted using the spot rate at the time that they were paid.

3.59. 'Uncertain' costs refer to contingency, variation orders, and uncertain resource costs incurred in a foreign currency; these are costs which may be difficult or impractical to hedge. We expect the level of uncertain costs to be reasonable. For uncertain costs, we either:

- apply the same blended rate as for the firm costs to convert them to GBP; or
- at the developer's request, and with sufficient justification for its merit, convert all uncertain costs to GBP using the spot rates applicable at the time that the costs are incurred. This will require the cash flow profile of uncertain costs to be provided at InTV, ITV and FTV, with revisions made at each stage to take account of both the movements in spot rates and any time or volume changes in the spend profile.

3.60. We assume that between InTV and ITV, or ITV and FTV, any increase or decrease in the total costs incurred in foreign currencies will be due to changes in uncertain costs. Therefore, any changes to total costs in foreign currencies will be incorporated into our assessment by adjusting the uncertain cost balance.

3.61. When a developer awards a contract, there may be a long duration until the contract is signed and the cost of the contract made firm. There may be an exchange rate true-up in the contract terms to cover any currency fluctuations over this period. If this is the case and there are indications that there will be significant period between contracts being awarded and being signed, we expect developers to take a hedging option to mitigate currency and commodity movements during this period. We consider this to be the most economic and efficient way to mitigate any losses.

Outstanding costs

3.62. When the cost assessment process is completed, cash payments made by the developer may not equal the FTV because there may be a number of outstanding non-cash items such as retentions, accrued invoices and provisions for work that is yet to be completed. If the level is significant (e.g. greater than 5% of the value of the

Transmission Assets), we may delay our final assessment.[11] Where we consider that non-cash items are reasonable and do not amount to a significant percentage of the FTV, they will be treated as a firm commitment by the developer to allow the assessment to be completed.

Treatment of cost overruns

3.63. The Capex costs that developers submit for consideration during the FTV stage may vary from the ITV estimate as the construction progresses. For example, a number of projects have experienced construction and cost overruns during the installation of subsea export cables for a number of reasons, including unforeseen events.

3.64. When significant construction cost overruns or variation orders arise, we expect developers to discuss these matters with us in a timely manner. In such circumstances, we may undertake an investigation, supported by our advisers, to inform our decision on whether submitted costs are economic and efficient and should be included in the FTV. We will consider each case on a project specific basis, as issues that arise may not be common across projects. To inform our decision-making, we may instruct our advisers to liaise closely with the developer, to assist us in understanding, amongst other things, the decisions and mitigating actions taken.

3.65. To facilitate conclusion of the cost assessment process in a timely manner, developers are advised to provide, as a minimum, the following supporting information:

• A detailed explanation of each cost overrun, including the root cause(s)	• the chosen solution(s) with technical justification (where relevant)
• a chronological order of events	• the associated risk assessment
• solutions considered and costs of those solutions	• whether the event was insurable
• the preferred option, why it was chosen and the cost of that option	• details of claims and supporting board papers

3.66. Without this information, we may be unable to determine whether the costs are economic and efficient. This could cause a delay to the cost assessment process and exclusion of unjustified cost overruns in the FTV. Under the Tender Regulations[12], where developers fail to provide information by a required date, the Authority may decide not to take into account the information provided when determining the ITV or FTV.

Capitalisation of operating costs

3.67. We do not allow the capitalisation of operating costs as this is not within the scope of our OFTO cost assessment process. Operational costs are those costs that have been (or will be) incurred after the point at which the Transmission Assets are available for use for the transmission of electricity; examples include: operations and maintenance costs, fishery disturbance payments, crop loss compensation payments, land lease and

[11] If necessary, we could use the PTRA mechanism to avoid delays to the transaction (see paragraph 2.22).
[12] Regulation 4(7) of the Tender Regulations.

easement payments, insurance costs, post-construction environmental monitoring, and storage of cable and equipment spares.

Depreciation of operational projects

3.68. The design life indicated by manufacturers for offshore Transmission Assets is generally greater than the OFTO's revenue entitlement period.[13] On this basis, although some projects may be operational for a period of time prior to the Transmission Assets being transferred to the OFTO, we consider it reasonable not to apply depreciation to the assets' FTV. However, we will keep this under review and consider depreciation on a case-by-case basis.

Anticipatory and wider network benefit investment

3.69. The projects that have been through the cost assessment process to date have been simple radial (point-to-point) connections. However, some future projects may have coordinated grid connections, which involve additional capability, within their Transmission Asset design, to connect future offshore generation projects, or provide wider network benefits. We consider two types of Anticipatory Investment, as follows.

Developer-led Wider Network Benefit Investment

3.70. In its current role of making connection offers, the system operator (**SO**) may already request that a developer of offshore generation includes Wider Network Benefit Investment (**WNBI**) in its project if the SO believes this would support the economic and efficient development of the network.

3.71. We are not aware of any connection offers to date that include developer-led WNBI. However, where this is the case, we have previously proposed that we would carry out 'gateway assessments' to minimise the risk of consumers bearing the cost of 'stranded' Transmission Assets and to give developers comfort on their route to cost recovery for the developer-led WNBI included in their project. Through the gateway assessments, we would review the rationale for including the WNBI in the developer's project. If, under the gateway assessment, we consider that the WNBI would be in the interests of consumers, we would include the costs of WNBI in the cost assessment as part of a subsequent offshore tender. This provides the developer with confidence that they are able to recover the economic and efficient costs of the additional investments. For more information on gateway assessments, please see our latest conclusion document on the matter.[14] Where a developer receives a connection offer that includes developer-led WNBI, we encourage them to contact us to discuss the offer and the potential for a gateway assessment.

[13] The revenue entitlement period for projects from TR1 to TR5 is 20 years. For projects included in TR6 and onwards, the revenue entitlement period is up to 25 years.
[14] "Integrated Transmission Planning and Regulation (ITPR) project: final conclusions" Ofgem 17 March 2015

Generator Focused Anticipatory Investment

3.72. Generator Focused Anticipatory Investment (**GFAI**) is a type of Anticipatory Investment in offshore transmission infrastructure which is led by a developer to support the later connection of specific offshore developments. We consider that the developer of the generation project for which GFAI is undertaken, is best placed to manage the associated stranding risk. In July 2013, we confirmed our view that consumers should be protected from increased stranding risk, through user commitment type arrangements and that, subject to the effective management of stranding risk, developers could be given greater confidence on the route to cost recovery for the scope of GFAI undertaken. The Transmission System Operator has consulted on how best to manage stranding risk associated with GFAI and has decided that bespoke arrangements should be agreed for each project.[15]

3.73. We note that developers can be required to carry out work on several separate projects in one operation, as part of their Development Consent Order approval. For example, a developer may be required to lay onshore cable ducting in different projects in one combined operation to minimise the environmental impacts. At present, in these circumstances developers will only be able to recover costs in the cost assessment process directly applicable to the specific project being considered (this is subject to any changes noted under paragraph 3.75 below). Therefore, if, for example, a developer lays ducting for two projects at the same time, the costs associated with laying ducting for each project will be recovered separately in each project's individual cost assessment. In such a scenario, assets in construction will only attract IDC while work is ongoing for that specific project.[16]

3.74. Where developers are required to do Anticipatory Investment work for other developers, we would review how they should be remunerated on a case-by-case basis.

3.75. Currently the Offshore Transmission Network Review (OTNR)[17] is looking at the way that the offshore transmission network is designed and delivered. The outcomes of this project will be monitored to assess any impact on the way we treat anticipatory investment and this guidance will be updated as necessary. As noted in the latest update on greater coordination in the development of offshore energy networks[18], further details on the process for anticipatory investment, including proposed changes to cost assessment guidance, will be the subject of future publications.

Ancillary services

3.76. We are now encountering projects that are developing the ability to offer additional energy services. Examples of these include battery storage, shunt reactors and synchronous condensers. There are several projects investigating the provision of these services and their categorisation is still under discussion and we will update this guidance as necessary when discussions are complete. The underlying treatment of any costs

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[15] "Conclusions Letter on GFAI User Commitment" National Grid April 2015
[16] For further information on IDC, see paragraphs 3.90 to 3.103.
[17] https://www.gov.uk/government/groups/offshore-transmission-network-review

[18] https://www.ofgem.gov.uk/publications/update-following-our-consultation-changes-intended-bring-about-greater-coordination-development-offshore-energy-networks

relating to ancillary service provision will be still be done on the basis that the assets are being classed as Transmission Assets and the cost associated with them being demonstrated as economic and efficient. If the assets are not classified as being Transmission Assets they will not be included in the cost assessment process.

Exceptional events

3.77. Some developers have submitted additional costs associated with exceptional events, such as Covid 19. Our approach to these additional costs is the same as for any cost overrun (see para 3.63); the developer must provide evidence that all options were explored to mitigate any additional costs and that the option taken was the most economic and efficient approach available at the time. Additional costs in relation to exceptional events will be assessed on a case-by-case basis.

"Other" costs

What do we mean by "other" costs?

3.78. Before commencing the construction of Transmission Assets, the developer would usually undertake a front-end engineering design process, followed by a detailed process to obtain the relevant consents and permissions that are required for constructing assets offshore and onshore. For example, detailed surveys of the seabed will be required to ensure that the assets avoid existing apparatus or seabed wreckage, and a detailed environmental impact assessment will be required to satisfy statutory requirements. The onshore cable route for the Transmission Assets will require detailed planning to avoid existing assets (e.g. pipes, cables, roads and railway tracks), to take account of land conditions and in some cases special measures may be required to satisfy local planning arrangements. Obtaining the relevant consents will involve project management services and the use of specialist equipment and contractors. We generally refer to these costs as pre-construction development costs.

3.79. When the project enters the construction period, project management and some development activities will continue. End-to-end PM costs, as well as development costs, are costs common to the entire project (including Generation and Transmission Assets) and are assessed as part of the development costs, while direct PM costs are included and assessed against the Capex costs in the relevant assets' costs categories.[19] The approach to managing the construction and day-to-day control of contractors has varied across developers; for example, some have project managed via in-house resources and others have outsourced project management or contracted out the supply and installation through a turnkey contract.

3.80. Through the cost assessment process, we will review the developer's historical and ongoing development costs. Set out below is an overview of the analysis that we will undertake to ensure that the total development costs, included in the cost assessment processes, are allocated appropriately, and are economic and efficient.

[19] See paragraphs 3.23-3.24 for further details.

Assessment of "other" costs

Allocation and accuracy of costs

3.81. Development costs, end-to end PM costs and other end-to-end shared costs (like insurance and health and safety related costs) are reported in the CAT under the category "other".

3.82. Some development costs are unequivocally assigned to either the Generation or the Transmission Assets. This is the case when costs are documented by, for example, a purchase order or an invoice. It is our preference to allocate external costs directly to the generation or transmission part of the project, whenever possible.

3.83. Other development costs may not be clearly attributable to either the generation or transmission construction activities, as they relate to the process of developing and constructing the project as a whole (spanning both Generation and Transmission Assets). In this case, a suitable allocation methodology should be established and applied by the developer in the same way as proposed for Capex costs (see paragraphs 3.5 to 3.13). We will assess the robustness of any such allocation methodology. We will also consider the robustness of reasons given for any development cost changing during the cost assessment process. To support this analysis, we require developers to provide a detailed breakdown of their development expenditure, ongoing end-to-end PM costs. and other end-to end costs.

3.84. Historically, developers have adopted different approaches to reporting their development costs. For example, some have reported ongoing project management within construction packages, while others have reported these at an aggregated cost level. It is important for Ofgem to be able to benchmark costs in a consistent manner. Therefore, costs associated with specific elements of a project should be allocated to that package; for example, project management of the onshore substation work package represents a 'direct PM cost' and should be in the onshore substation cost category. End-to-end project management and other development costs (like consents) will be allocated to the "other" cost category. If costs associated with developing an asset are identifiable, we would expect the developer to allocate those costs to that asset. Where necessary, we will instruct developers to reallocate costs that have been incorrectly classified, so that costs can be fairly compared at both the work package and overall project levels.

3.85. In a number of cases, particularly for historical development costs like seabed surveys which cover the whole of the project, developers may be unable to provide a supporting metric for the transmission elements and consequently base allocations on estimates. The developer must provide a robust rationale and evidence to support the proposed allocation, especially if the costs in question are predominantly generation-related. If a developer is unable to do so, we will either adopt a general cost allocation rate used elsewhere on the project[20] or exclude an amount of the cost in question from the transfer value.

[20] For example, a ratio of the direct costs of Generation Assets to the direct costs of Transmission Assets.

3.86. Where projects have been acquired from another party, the total acquisition cost paid by the developer may include aspects related to both generation and transmission. Only the costs which relate to the development and/or construction of the Transmission Assets (and their associated financing costs which are assumed to be included in the acquisition cost), may be included in the FTV. This may require the developer to use an appropriate allocation metric to split such costs between transmission and generation. The developer should not include any profit, premium or goodwill, which forms part of the acquisition cost, as such elements reflect the value of the generation capacity rather than the transmission component.

Efficiency of development costs

3.87. In calculating the FTV, we will review whether development costs are broadly in line with the range provided by our advisers. Where these differ markedly, we will undertake additional analysis to ensure that only appropriate development costs are allowed.

3.88. We have completed the cost assessment process for seventeen offshore projects. We have found that, on average, resources costs (including development and end-to end PM costs) do not exceed 15% of Capex.

3.89. For some projects, we have capped the allowed resources costs at 15% of the allowed Capex. In the absence of any project-specific evidence that demonstrates the efficient development costs to be above this level, we will continue to cap development costs at 15% of the allowed Capex.

Interest during construction (IDC)

What do we mean by IDC?

3.90. IDC refers to the financing costs incurred by a developer in funding the development and construction of the Transmission Assets. Industry commonly recognises these financing costs as part of capital expenditure. For the purposes of the cost assessment, we consider IDC to be an efficient cost of capital during the development and construction period of the Transmission Assets. However, the IDC rate that we apply may not be at the same rate or for the same duration that a developer has actually incurred costs.

Allocation and assessment of IDC

Allocation of IDC

3.91. IDC is only applicable to the cash flow representing the actual allowed Capex and Development costs [21] associated with the Transmission Assets. When changes are made to the developer’s submitted costs by re-allocation of costs to the Generation Assets or

[21] For further information of what constitutes Capex and Development costs, see paragraphs 3.4 and 3.78-3.79 of this document.

by assessing efficiency of the costs submitted, these will be reflected in the cash flow. This ensures that the IDC calculated for the Transmission Assets relates to the economic and efficient cost of developing and constructing the assets.

3.92. IDC is applicable separately to each project, and is not applied across multiple projects. See the section on "Generator Focussed Anticipatory Investment" for details on investments made in anticipation of future projects. IDC will cease when the work is completed on the anticipatory investment(s) and will not resume until work is commenced on the subsequent project and on those specific anticipatory assets. IDC will not be accrued over the period of no active construction and will only be applied to the specific assets when they are back in the course of construction, not at the point when the subsequent project starts construction.

3.93. IDC is only allowed on the actual cash flow representing payments made against the contracts for developing and constructing the Transmission Assets. We do not apply IDC to accounting data as it does not represent the actual cash cost to the developer and may include non-cash elements such as retentions, accruals for work completed but not invoiced, unpaid invoices, any set-off amounts deducted and provisions.

Efficiency of IDC

3.94. The purpose of allowing developers to claim IDC is to recompense them for the economic and efficient costs of financing the development and construction of the Transmission Assets. The 'economic and efficient' test applies in respect of the rate of IDC allowed, the period for which IDC is being applied and the costs for which IDC is attached; these are set out and discussed below.

Interest rate applied to the project

3.95. We calculate IDC on a pre-tax nominal basis. The use of a pre-tax rate ensures that developers adopt a rate that enables them to meet the expected level of tax in the chargeable gain which arises from the inclusion of financing costs in the assessed costs.

3.96. The level of IDC should reflect the average rate that the developer (or in the case of corporate supplied funds, its corporate sponsors) has incurred on the funds provided. Generally, the funds may come from providers of both equity and debt. The rate we allow is the rate that an efficient and economic transmission company engaged in this type of activity has (or ought to have) incurred. This is not necessarily the rate that has been incurred by a developer on the generation element of the Qualifying Project.

3.97. The developer must substantiate its claim for IDC with relevant documentation, for example evidence of the target discount rate approved for such projects, or the expected return, if lower. Such rates should include the quantum and rate from lower cost debt funding where obtainable. If we consider the rate proposed by the developer to be excessive, relative to its funding sources, we will assess the rate that should apply based on the weighted average of its funding sources.

3.98. We publish an annual decision on appropriate IDC rates to allow developers for projects that take a Final Investment Decision (FID) during that year. The IDC cap is fixed at the date of FID and applies for the efficient duration of construction until the Transmission Assets become available for use for the transmission of electricity.

However, if we determine that a developer makes FID to lock in a favourable IDC rate and/or is not progressing a project at a sufficient pace beyond that point, we may adjust both the rate and the period of applicability to reflect those that would have applied if FID had been taken at the most appropriate point in time.

3.99. We will conduct an annual review of the cap to ensure that it remains responsive to market movements. It is important to note that changes arising from such reviews will not affect projects that have already reached FID. A decision to change the cap will be communicated prior to coming into force, following a consultation where appropriate.

Duration of the financing

3.100. The approach taken to each project will be specific to that project's arrangement of assets and we will discuss with the developer the IDC treatment for its project during the ITV stage. The IDC treatment will take into account the following guidance principles:

3.100.1. In general, IDC will cease as soon as Transmission Assets <u>are available for use for the transmission of electricity to the onshore network</u>. For larger and more complex projects this could mean that IDC ceases on part of the Transmission Assets but continues to be payable on a reduced portion of Capex corresponding to the Transmission Assets still under construction. The IDC during this period will be calculated by adjusting the accrued IDC earning Capex balance, using a ratio of the cost of the Transmission Assets that are under construction and the other Transmission Assets that are now available;

3.100.2. Transmission Assets will be considered "available for use for the transmission of electricity to the onshore network" at the point at which we consider that those assets have been safely energised and commissioned. This point will be project specific and may or may not align with the stages of the developer's construction programme and/or with the point at which a completion notice is issued to Ofgem for those Transmission Assets;

3.100.3. IDC for a specific project will be determined with reference to the <u>energisation and commissioning of the Transmission Assets only</u> and not energisation and commissioning activities that are associated with the wind farm Generation Assets. There may be occasions where Transmission Asset and Generation Asset commissioning activities occur in parallel; and

3.100.4. As a general rule, each time an offshore substation becomes available for use, we will consider the cables and other transmission equipment directly associated with that substation to also be available. Where a project has an interlink cable connecting different offshore substations, we may treat the energisation of the interlink as a signal that the interlink and associated substations connected to it have become available.

3.100.5. IDC will not be allowed on assets that are not actively in the course of construction. For example, a cable may be 'wet' stored (left on seabed) for a period of time before being installed and terminated. If we consider this period to be inefficient or there is no construction activity occurring, we will adjust the IDC allowed to reflect this. This applies to all asset types, not just subsea cables.

3.100.6. For IDC on GFAI (see 3.72), IDC will only apply to anticipatory investments while those specific assets are actively in the course of construction.

3.101. As projects have become larger and more complex, we have and will continue to refine the cost assessment process to ensure that any costs incurred and paid can be considered economic and efficient. We will consider the length of time over which IDC is applicable, and if we consider there is evidence of inefficient and uneconomic time periods during the pre-construction, construction or commissioning programme for the Transmission Assets, the period of IDC applicability may be adjusted to reflect this.

Eligible costs

3.102. IDC will not be applied to costs deemed to be inefficient, and will also be curtailed in line with any Capex reductions made to the project.

3.103. Where projects have been purchased from other developers, we consider that the IDC should commence on the date of the acquisition. IDC is not applied to the period over which the previous developer incurred costs because the purchase cost should already reflect suitable remuneration for financing costs over that earlier development period.

Transaction costs

What do we mean by transaction costs?

3.104. Transaction costs relate to costs that a developer has incurred during, and as a consequence, of the Tender Process. These costs are generally reviewed at the FTV stage of the cost assessment process and include:

- tender fees payable to Ofgem; and
- the developer's internal and external costs as a result of the Tender Process.

Assessment of transaction costs

Costs incurred by Ofgem's cost estimate exercise

3.105. Fees payable by the developer to Ofgem under the Tender Regulations[22] to cover Ofgem's costs in conducting the cost assessment process are recoverable as transaction costs.

Developer's internal and external costs

3.106. To support their activities in the Tender Process, developers may have had to utilise a range of resources or services including, for example, producing legal documents in connection with asset transfer or taking financial advice to support the cost assessment process. The developer's internal and external costs should not include activities that relate to generation activities.

3.107. We require developers to submit evidence to support the level of external and internal costs that they have submitted. These costs may be reviewed as part of the forensic accounting investigation.

3.108. For internal costs, developers are required to submit the names of personnel involved, the activities that they worked on, their day rates and the number of days spent on tender activities versus the number of days spent on the total project (non-tender related activities) in order to substantiate any claims for such costs. Any mark-up or margin on such internal resources would not be accepted into the transfer value.

3.109. There may also be internal specialised staff charged directly to the project for undertaking work directly related to the Tender Process, for example this could include engineers, accountants, etc. Where this is the case, we would similarly require appropriate evidence.

[22] Regulation 5 (Payment of costs) of the Tender Regulations.

Taxation

Value added tax (VAT)

3.110. HMRC has provided guidance in relation to whether the transfer of Transmission Assets can be viewed as a transfer of a business as a going concern (**TOGC**).[23] HMRC has indicated that they would expect (subject to exceptional circumstances) that any Transmission Assets that are currently operational or fully constructed up to the point of operation at transfer would meet the TOGC conditions. Should any circumstances occur in which the transfer does not meet TOGC conditions and therefore is not free of VAT (eg as a result of further discussions between the developer, Preferred Bidder and HMRC), then the parties should seek arrangements with HMRC to minimise the working capital consequences of such a situation. This will have no impact on the assessment of costs or assessed transfer value.

Capital allowances

3.111. Each transfer of Transmission Assets from a developer to an OFTO under a Generator Build tender exercise is for a set of assets on an as-built basis, based on actual expenditure. We therefore assume for the cost assessment process that the OFTO, as purchaser, will obtain the full benefit of all available capital allowances.

3.112. Where benefits do not fully pass across and any such tax benefit is retained by the developer (eg as a result of agreement reached between the developer and the Preferred Bidder), which results in the OFTO not being able to obtain the full benefit of all available capital allowances, we will reduce the assessment of costs. This reduction will be for an amount that reflects the value of the tax benefit retained by the developer.

[23] Transfer a business as a going concern

Appendices

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Appendix	Name of Appendix
1	Cost Assessment and Tender Process
2	Summary of CAT cost categories
3	Glossary

Appendix 1 – Cost Assessment and Tender Process

1.1. Table 1 below summarises the stages involved in the cost assessment process and how these stages fit in with the stages of the Tender Process. This is provided for illustrative purposes only as the stages may differ for individual projects and tender rounds.

Table 1

Tender Process	Cost Assessment Process
Qualifying Projects and Tender Entry Conditions A developer provides Ofgem with information on their project. The project must satisfy certain conditions, stated in the Tender Regulations, in order to become a Qualifying Project and for Ofgem to commence the tender. The qualifying project must satisfy certain conditions notified by Ofgem (the **Tender Entry Conditions**). Ofgem determines whether the project meets the Tender Entry Conditions and notifies the relevant developer. **Tender Commencement** Ofgem publishes a tender commencement notice including a list of projects that have qualified for the tender. Following this, Ofgem publishes a Preliminary Information Memorandum on the project, which includes an Initial Transfer Value (**InTV**) for the project.	**First view on costs – Initial Transfer Value (InTV)** Ofgem requests a 'first view' from the developer of how much their offshore Transmission Assets will cost to build. Ofgem sends the developer a pro forma cost template which requires them to break down their costs into certain categories. Ofgem sets an Initial Transfer Value (**InTV**) based on the submissions by the developer. Ofgem completes high level checks on the data but does not analyse these costs in detail at this stage. The InTV for the project is published by Ofgem in the Preliminary Information Memorandum and/or the EPQ document.
Enhanced Pre-Qualification (EPQ) Ofgem publishes an EPQ document which sets out a range of requirements the bidders (potential OFTOs) must show they meet to participate in the next stage of the bidding process. After the evaluation of EPQ submissions, Ofgem publishes the shortlist of bidders who have qualified to proceed to the next stage. Ofgem may also provide feedback to bidders at this stage. **Invitation to Tender (ITT)** Ofgem publishes an ITT document to the shortlist of bidders. This outlines the evaluation criteria Ofgem will consider when determining a preferred bidder (**PB**), as well as the ITV. Potential OFTOs then collate and submit their bids based on all the information published by Ofgem and provided by the developer via a data room. After evaluating the bids, Ofgem announces a PB who then moves to the next stage	**Indicative Transfer Value (ITV)** During the EPQ stage of the Tender Process, Ofgem and its advisers carry out a detailed cost assessment review, a forensic accounting review and, where relevant, a technical analysis of the costs submitted by the developer. The findings of this work are used to establish the Indicative Transfer Value (**ITV**) of the project. The ITV for the project is published by Ofgem at the commencement of the ITT stage.

Preferred Bidder (PB) The PB and the developer will agree the form of documents relating to the transfer of the Transmission Assets. Ofgem will draft a project specific offshore transmission licence. This will include the 25 year[24] tender revenue stream bid by the PB and modified according to the Final Transfer Value (**FTV**). At this point a 28-day Section 8A Consultation[25] takes place. This provides an opportunity for other parties, particularly unsuccessful qualifying bidders, to see the tender revenue stream value bid by the PB. **Successful Bidder and Licence Grant** This stage starts with a notice from Ofgem of its intention to grant the licence to the Successful Bidder. After a 'standstill period', the final commercial documents are executed and the OFTO Licence is granted and published. This is followed by financial close and asset transfer.	**Final Transfer Value (FTV)** During the PB stage of the tender process, Ofgem finalises the cost assessment for the project based on updated information from the relevant developer. As with the ITV stage, Ofgem employs accounting advisers and, where relevant, technical advisers to carry out a review of all contract expenditure. Ofgem sends the developer and the PB a draft cost assessment report incorporating a Final Transfer Value for the Transmission Assets of the project. After allowing an appropriate time for review and comments (normally two weeks), Ofgem will publish the cost assessment report at the same time as the publication of the section 8A notice. The published report may include redactions to preserve commercial confidentiality.

[24] 25 years from TR6 onwards, 20 years for TR5.
[25] Section 8A Electricity Act 1989.

Appendix 2 – Summary of CAT cost categories

CAT Template, cost reporting

[name] Offshore Windfarm Development	
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	Transaction costs

CR1 - Cost overview

[name] Offshore Windfarm Development				
Costs Overview	Original Projected Costs (£)	Currently Projected Costs (£)	Variance (Current - Original) (£)	Cost Movement Commentary
Offshore Substation(s)	£0.00	£0.00	£0.00	
Submarine cable(s) supply & installation	£0.00	£0.00	£0.00	
Onshore cable(s) supply & installation	£0.00	£0.00	£0.00	
Reactive Substation	£0.00	£0.00	£0.00	
Onshore substation	£0.00	£0.00	£0.00	
Connection	£0.00	£0.00	£0.00	
Other	£0.00	£0.00	£0.00	
Transaction	£0.00	£0.00	£0.00	
Total capital costs (includes contingency, claims, variations & future costs)	£0.00	£0.00	£0.00	
IDC	£0.00	£0.00	£0.00	
Total costs	£0.00	£0.00	£0.00	

CR2 – CR9 categories and related cost

Cost category	Costs included
CR2 - Offshore Substation	*Design of piles/jacket/monopile*
	Supply of piles/jacket/monopile
	Installation of piles/jacket/monopile
	VOs piles/jacket/monopiles
	Design of topsides
	Supply of topsides
	Installation of topsides
	Design, Supply and Installation of electricals
	Category specific project management
	Other shared OSP costs (examples are: Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO, SCADA equipment, J-Tubes)
	Spares
	Contingency
CR3 - Submarine Cable	***Export Cable(s)***
	Design and supply
	Installation
	Other shared costs (examples are: Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO*)*
	Spares
	Contingency
	Interlink(s)
	Design and supply
	Installation
	Design, supply and installation of electricals
	Share of accommodation associated with interlink(s)
	Interlink J tubes
	Share of OSP structure associate with interlink(s)
	Spares
	Contingency
CR4 – Onshore cable	*Supply of cable*
	Installation of cable
	HDD
	Crossings
	Onshore site preparation
	Category specific project management
	Other shared land cable costs (examples are: Land owner agreements, Crop compensation*)*
	Spares
	Contingency
CR5 – Onshore Substation	*Design, Supply and Installation of electricals*
	Design Civils
	Onshore site preparation
	Construction
	Other shared ONS costs (examples are: Land owner agreements, SCADA, Crop compensation*)*
	Project management
	Spares
	Contingency

Cost category	**Costs included**
CR6 – Reactive Substation	***Reactive & Harmonic Equipment*** *Design & Supply (*Onshore Reactive, Onshore harmonics) *Design & Supply (*Offshore Reactive, Offshore harmonics) *Project management* *Spares*
	Contingency
	Mid-point compensation platform
	Design of piles/jacket/monopile
	Supply of piles/jacket/monopile
	Installation of piles/jacket/monopile
	VOs piles/jacket/monopiles
	Design of topsides
	Supply of topsides
	Installation of topsides
	Category specific project management
	Other shared OSP costs (examples are: Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO, SCADA equipment*)* *Spares*
	Contingency
CR7 – Connection	*Cable - supply and install*
	Grid connection agreement
	Connection works (developer or onshore TO)
	Project management
	Contingency
CR8 – Other	*End to end shared costs (examples are:* Insurance*,* Legal fees, HSEE*)* *Development (examples are:* Acquisition Costs, Design & resources, Consents & environmental planning) *End to end project management*
CR9 – Transaction	*Overall project contingency* *Transaction costs*

Appendix 3 – Glossary

A

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

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

B

Best and Final Offer (BAFO) Stage
A stage of a Tender Exercise which the Authority may decide to run after the ITT Stage in order to determine which Qualifying Bidder shall become the Preferred Bidder in respect of a Qualifying Project. The stage will commence with Ofgem distributing the BAFO document to selected Qualifying Bidders and includes the preparation, submission and evaluation of BAFO submissions and ends when a Preferred Bidder is selected and notified.

Bidder
Any person or Bidder Group that makes a PQ, EPQ, QTT, ITT or BAFO submission in accordance with the Tender Regulations.

Bidder Group
Two or more persons acting together as a consortium for the purposes of any PQ, EPQ, QTT, ITT or BAFO submission to Ofgem in accordance with the Tender Regulations.

C

Capex
Capital Expenditure – defined as the costs involved in the delivery, construction and installation (including civil works) of offshore Transmission Assets.

Cost Assessment Template (CAT)
The pro-forma cost assessment template provided by Ofgem to the developer which the developer should use to submit its costs information. The information required to be included in the CAT is set out in Appendix 2 to this document.

D

Developer
The Tender Regulations define a 'developer' as 'any person within section 6D(2)(a) of the Electricity Act 1989'. Section 6D(2)(a) of the Electricity Act defines such person as 'the person who made the connection request for the purposes of which the tender exercise has been, is being or is to be, held'. In practice, such person is also the entity responsible for the construction of the Generation Assets and, under Generator Build, the Transmission Assets. Under Generator Build, this is the person who requests that Ofgem commence the Tender Process in respect of a proposed project.

E

Direct PM costs
Has the meaning given in paragraph 3.23 of this document.

Electricity Act
The Electricity Act 1989 as amended from time to time.

End-to-end PM costs
Has the meaning set out in paragraph 3.23 of this document.

Enhanced PQ (EPQ) Stage
An extended version of the PQ stage of the Tender Exercise that can be used for Generator Build projects where the Authority decides not to run a QTT Stage. At the end of the EPQ Stage, the Authority will determine which Bidders become Qualifying Bidders and will be invited to participate in the ITT Stage of the Tender Exercise for each Qualifying Project.

F

FID
Final investment decision, is a final decision of the Capital Investment Decision (CID) as part of the long term corporate finance decisions based on key criteria to manage company's assets and capital structure. It is the point at which contracts for all major equipment can be placed, allowing procurement and construction to proceed and engineering to be completed.

Final Transfer Value (FTV)
The final transfer value set by Ofgem in accordance with paragraphs 2.17 to 2.21 of this guidance document.

G

Generation Assets
The assets forming the generation elements of the project which are to be retained by the developer.

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

I

IDC
Interest during construction. As set out in paragraph 3.89 of this document.

Indicative Transfer Value (ITV)
The indicative transfer value set by the cost assessment team, as set out in paragraphs 2.12 to 2.16 of this document.

Initial Transfer Value (InTV)
The initial value set by the cost assessment team as set out in paragraph 2.9 of this document.

Invitation to Tender (ITT) Stage
The stage of a Tender Exercise during which the Authority may determine which Qualifying Bidder becomes the Preferred Bidder or whether to hold a BAFO Stage. This stage commences with the distribution of the ITT Document to Qualifying Bidders by Ofgem and includes the preparation, submission and evaluation of ITT submissions.

ITT Document
The document prepared and issued by Ofgem to each Qualifying Bidder invited to make a submission at the ITT Stage, and which sets out the rules and requirements of the ITT Stage.

L

Licence Grant
Following its determination to grant an OFTO Licence to the Successful Bidder, the Authority confirms such determination in accordance with regulation 29(5) of the Tender Regulations and grants such OFTO Licence to the Successful Bidder pursuant to section 6(1)(b) of the Electricity Act.

O

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

OFTO
Offshore transmission owner.

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

OSP
Offshore substation platform.

P

Post-Tender Revenue Adjustment (PTRA)
An adjustment to the Base Transmission Revenue (as defined in the OFTO Licence) under Amended Standard Condition E12-A3 of the OFTO Licence to account for any difference between the Indicative Transfer Value and the Final Transfer Value.

Preferred Bidder (PB)
In relation to a Qualifying Project, the Bidder determined by Ofgem following its evaluation of the submissions received, to which Ofgem intends to grant the OFTO Licence subject to the satisfaction of the conditions specified by Ofgem in accordance with the Tender Regulations.

Q

QTT Stage
Qualification to tender stage.

Qualifying Bidder
Any person or Bidder Group that is invited to make an ITT Submission, a Preferred Bidder, a Reserve Bidder or a Successful Bidder (as applicable).

Qualifying Project
An offshore transmission project in respect of which Ofgem determines that the developer has satisfied the requirements set out in paragraph 2 of Schedule 1 to the Tender Regulations, or

will use its reasonable endeavours to satisfy the relevant Qualifying Project requirements within a period specified by Ofgem.

S

Section 8A Consultation
The public consultation required by section 8A of the Electricity Act for any modifications to the standard conditions of the OFTO Licence to be made at Licence Grant. The modifications are required in order to incorporate the project specific provisions in the relevant licence. The consultation must run for at least 28 days.

Successful Bidder (SB)
The Preferred Bidder in a Tender Exercise who has resolved the PB Matters (as defined in the TPGD) to the Authority's satisfaction, such that the Authority intends to grant to it an OFTO Licence.

T

Tender Exercise
Each tender exercise run in accordance with the Tender Process.

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

Tender Process Guidance Document (TPGD)
The guidance document setting out the Tender Process. A link to the most recently published guidance (as at the date of publication of this guidance document) is contained in section 1, p.5.

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

Tender Revenue Stream (TRS)
The payment an OFTO receives over its revenue term.

Transmission owner (TO)
An owner of a high-voltage transmission network or asset.

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

Transmission Network Use of System (TNUoS) charges
Charging arrangements that reflect the cost of installing, operating and maintaining the transmission system.