Offshore Transmission: Cost Assessment for the Westermost Rough transmission assets

Decision

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Overview:

This document sets out the cost assessment for the Westermost Rough (WMR) offshore transmission assets and the key principles that we have applied in our cost assessment process for the third transitional tender round. The Authority has granted an offshore transmission licence to TC Westermost Rough OFTO Limited, incorporated by the consortium of Transmission Capital Partners Limited Partnership and International Public Partnerships Limited.

TC Westermost Rough OFTO has incorporated the assessed transfer value as set out in this report into their tender revenue stream. The appendices published alongside this report are available on the Ofgem website. They include correspondence between Ofgem and the developer as part of the cost assessment process and external consultants' reports.

Context

Ofgem and the Department of Energy and Climate Change have developed a regulatory regime for offshore electricity transmission. A key part of this regime is that an offshore electricity transmission licence will be granted to an Offshore Transmission Owner (OFTO) following a competitive tender process run by Ofgem.

The Electricity (Competitive Tenders for Offshore Transmission Licence) Regulations 2013 ("the Tender Regulations") came into force on 22 February 2013. The Tender Regulations set out the tender process framework for granting an OFTO licence, including how Ofgem will run future tenders under both the generator build and OFTO build options. The Tender Regulations apply to the WMR transmission assets.

The Tender Regulations set out the requirement for the Authority to calculate, based on all relevant information available to it, the economic and efficient costs which ought to be, or ought to have been, incurred in connection with developing and constructing the offshore transmission assets in respect of a project. The Tender Regulations provide for an estimate, followed by an assessment of costs, in relation to offshore transmission assets.

Where the Authority has determined to grant an offshore electricity transmission licence to the successful bidder in respect of a particular project, the assessment of costs shall be used by the Authority to determine the value of the transmission assets to be transferred to the successful bidder. This value will be reflected in the revenue stream in the offshore electricity transmission licence granted to the OFTO.

Associated documents

- The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2013 Link
- Offshore Transmission: Tender Rules Link
- Interest During Construction for Transitional Tender Rounds Link
- Offshore Transmission: Guidance for Cost Assessment Link

Contents

Executive Summary

This document sets out Ofgem's assessment of the economic and efficient costs which ought to have been incurred in connection with the development and construction of the transmission assets for the WMR offshore transmission project ("the Project"). It also details the cost assessment process we have undertaken.

The cost assessment process involved the three key stages set out below:

- The initial calculation of costs based on the Developer's (WMR Wind Farm Limited) initial estimate was £199.5m ("the initial transfer value"). This was communicated to the Developer and published in the preliminary information memorandum (PIM) in 2014;

- The indicative estimate of costs was £172.3m ("the indicative transfer value"). The estimate was calculated as a result of further information regarding the development and construction of the Project being made available by the Developer and continuing analysis by Ofgem and its advisors. This updated calculation was communicated to the Developer in October 2014. The indicative transfer value was made available to bidders Enhanced Pre-Qualification (EPQ) stage of the tender process and was the transfer value assumed for the purpose of Invitation To Tender (ITT) stage submissions; and

- The assessment of costs is £156.7m ("the assessed costs"). This compares to the Developer's final submission of £168.9m, a reduction of £12.2m. The assessment is the Authority's calculation of the costs which ought to have been incurred in connection with the development and construction of the Project. The Developer has confirmed that the incoming OFTO will be able to obtain the full benefit of all available capital allowances. Therefore, this is the amount to be paid to the Developer by the OFTO for the transmission assets ("the final transfer value")

The key components of the initial, indicative and final transfer values, together with the Developer's submission of the latter, are given in table 1 below, followed by a summary of the movements between the Indicative Transfer Value (ITV) and the Final Transfer Value (FTV).

Table 1: Summary of cost components

Category	Initial Transfer Value February 2014 (£m)	Indicative Transfer Value October 2014 (£m)	Developer Proposed Transfer Value April 2015 (£m)	Final Transfer Value September 2015 (£m)
Capex	136.9	100.0	113.3	122.3
Development	30.7	48.4	40.5	23.1
Contingency	19.5	10.0	-	-
IDC	12.4	12.0	9.7	9.0
Transaction	-	1.9	5.4[1]	2.3
Total	**199.5**	**172.3**	**168.9**	**156.7**

[1] Includes £3.1m of Foreign exchange losses.

Capital expenditure (Capex)

The Capex component of the FTV increased by £22.3m since the indicative transfer value, due to a number of increases and decreases as set out below.

Increases of:

- £11.3m due to reallocation of costs from development to Capex;
- £2.9m due to export cable supply costs not included in the ITV;
- £3.2m due to onshore substation electrical costs not included in the ITV;
- £0.5m in foreign exchange losses;
- £9.1m in onshore substation, offshore substation and export cable construction costs.

These increases were offset by the following reductions:

- £1.5m in onshore civils works and additional site supervision;
- £1.0m due to reallocation to interim Operation and Maintenance (O&M) costs;
- £1.4m in offshore platform and export cable supply and installation costs not incurred;
  and
- £0.8m due to reallocating paint repair costs to generation assets.

Development costs

The Project's development costs have decreased by £25.3m to £23.1m since the indicative transfer value. The decrease is mainly due to: the reallocation of development costs to Capex; adjusting the metric used for allocating costs between generation and transmission assets; and, removing inefficient project management costs, estimated costs not incurred and reallocation to interim O&M costs.

Contingency

The contingency allowed in the indicative transfer value has been used in addressing additional Capex and development costs, while unused contingency has been released.

Interest during construction (IDC)

The IDC amount has decreased by £3m due to changes to the Project's cash flow as set out above, as well as removing IDC claimed for a period when the transmission assets were operational.

Transaction costs

The transaction costs are composed of both internal and external resource costs arising from the Developer's participation in the tender process. These have increased by £0.4m since the indicative transfer value. The increase is due to additional resource being required to close out the project. The developer submission included £3.1m of foreign exchange losses that were subsequently reallocated to Capex. Transaction costs have been assessed at £2.3m.

Final transfer value for the WMR transmission assets

In accordance with Regulation 4(2)(b) of the Tender Regulations, the assessed costs of the WMR transmission assets are £156,717,151. The final transfer value as determined by the Authority under Regulation 4(8) of the Tender Regulations is £156,717,151.

1. The cost assessment process

Chapter Summary

The Tender Regulations set out the requirement for the Authority to calculate, based on all relevant information available to it, the economic and efficient costs which ought to be, or ought to have been, incurred in connection with developing and constructing the offshore transmission assets in respect of a project. This chapter sets out the process that we followed in carrying out the cost assessment for the Project.

Overview of the cost assessment process

1.1. The Tender Regulations provide the legal framework for the process which Ofgem follows for the grant of offshore electricity transmission licences. This process includes calculating the economic and efficient costs of developing and constructing the offshore transmission assets to be transferred to the new OFTO.

1.2. The calculation of those costs shall be:

- Where the construction of the transmission assets has not reached the stage when those transmission assets are available for use for the transmission of electricity, *an estimate* of the costs which ought to be incurred in connection with the development and construction of those transmission assets; and

- Where the construction of the transmission assets has reached the stage when those transmission assets are available for use for the transmission of electricity, *an assessment* of the costs which ought to have been incurred in connection with the development and construction of those transmission assets.

Cost assessment principles

1.3. The cost assessment principles and overall process we have adopted in relation to various cost categories for tender rounds and the reasoning for such principles can be found in the document 'Offshore Transmission: Guidance for Cost Assessment'[2] (hereafter "the Guidance").

1.4. We have applied these principles in our cost assessment process for all the projects and, where appropriate, we have taken into account project specific circumstances.

1.5. The remainder of this chapter describes some of the key elements of the cost assessment process. Chapter 2 provides the detail as to how these have been applied to the specifics of the Project.

[2] Offshore Transmission: Guidance for Cost Assessment, Ofgem ref 183/12, Dec 2012

Data collection

1.6. To undertake cost assessments we gather and review a range of information and supporting evidence. These relate to the forecast and actual costs of developing and constructing the transmission assets that will transfer to the OFTO. Detailed cost information is provided by the Developer in the form of cost reporting templates, contract values, asset cost schedules and cashflows. The Developer also provided supporting evidence to substantiate their cost submissions including, amongst other things, contract documentation, supplier payment lists and invoices and receipts.

1.7. We have worked closely with the Developer and gathered information relating to the following cost categories in the development and construction of the transmission assets:

- Capital expenditure;
- Development costs;
- Contingency provisions;
- Interest during construction; and
- Transaction costs.

Process stages for cost assessment

1.8. The cost assessment process involves the key stages set out below.

Initial transfer value

1.9. The initial transfer value is based on cost submissions by the Developer for the project. This value is made available to bidders at the Pre-Qualification (PQ) or Enhanced Pre-Qualification (EPQ) stage of the tender process. The letter we send to the Developer at this time indicates that the calculation might be updated as a result of any further information provided by the Developer and our continuing analysis.

Indicative transfer value

1.10. We provide the ITV for the commencement of the Invitation to Tender (ITT) stage of the tender process. This value is used as an assumption underlying the tender revenue stream (TRS) bids submitted by bidders at the ITT stage. The letter we send to the Developer confirming the ITV indicates that the calculation might be updated as a result of any further information provided by the Developer and our continuing analysis.

Assessed costs

1.11. Once the transmission assets are complete or are close to completion and the Developer indicates that they have documentation to support an assessment, we commence an exercise to determine the assessed costs.

1.12. Following this assessment exercise, Ofgem sends the Developer a draft cost assessment report setting out the amount of the assessed costs. This gives the Developer the opportunity to correct factual errors and propose redaction of commercially sensitive information.

1.13. The draft report is also sent to the preferred bidder, to allow it to incorporate the assessed costs into their estimate of the TRS payable to the OFTO. This TRS amount, incorporating the assessed costs, is published in a consultation pursuant to section 8A of the Electricity Act 1989, by which the Authority proposes modifications to the standard conditions of the licence on a project specific basis ("the section 8A consultation")

1.14. The draft cost assessment report is published alongside the section 8A consultation. The report remains in draft form until the conclusion of the section 8A consultation and the Authority has determined to grant an offshore transmission licence to the successful bidder.

Final transfer value (FTV)

1.15. If the Developer retains some of the benefit of the available capital allowance we will reduce the relevant amount from the assessed costs before we derive the final transfer value. The FTV is confirmed once the Authority has determined to grant an offshore transmission licence to the successful bidder. After licence grant the final cost assessment report and supporting appendices is published on the Ofgem website.

1.16. Ofgem normally finalises the assessment of costs prior to commencement of the section 8A consultation, with the section 8A TRS accounting for 100% of the FTV.

Cost assessment analysis

1.17. We apply two tests when calculating the estimate and assessment of costs:

<u>Test 1 - Assessing the accuracy and allocation of Developer's cost submissions</u>

1.18. As a first test, we check the accuracy of the data provided by the Developer and the appropriateness of cost allocations, in particular, between the offshore generation and transmission assets. Throughout the cost assessment process the Developer provides cost information to us on an ongoing basis. Where we identify discrepancies in how the Developer has allocated these costs we check with the Developer to assess if they have been allocated to the correct asset category and make adjustments accordingly.

1.19. To support the cost assessment process we undertake a forensic accounting investigation. The scope of this investigation is shared with the Developer in advance. This investigation is based on the final costs that the Developer provides to us and applies to a sample of contract costs. The actual sample for each project varies due to the different contracting strategies adopted by the Developer and the specific needs of the project, but generally focuses on the most expensive contract and/or contracts which materially increase in cost.

1.20. The forensic accounting investigation scrutinises the cost allocations provided by the Developer. This may indicate the need for amendments to the Developer's submissions to reflect, for example:

- The actual costs incurred (e.g. in respect of exchange rates on foreign currency payments); and
- More relevant metrics for the allocation of shared service costs.

1.21. Where amendments in our opinion are required and in the absence of further evidence from the Developer to substantiate the original allocation, we incorporate the recommended changes from the forensic accounting investigation.

Test 2 - Assessing if a Developer's incurred costs are economic and efficient

1.22. Under the second test, we seek to assess, through appropriate analysis, whether the costs have been economically and efficiently incurred by the Developer. Where possible, we apply benchmarking and where industry wide cost indices are unavailable we review data from projects in the tender rounds. This analysis includes benchmarking across the projects and analysis in relation to funding interest rates. We consider such approaches to be an important tool in assisting us in determining what the economic and efficient costs should be.

1.23. To inform our cost estimate and assessment we undertake a benchmarking exercise. This is carried out using comparable costs across all transitional projects and any wider industry data to identify any cost outliers across the main cost categories. Any cost outliers we identify through the benchmarking exercise are subject to further review.

1.24. We also consider the procurement processes adopted by the Developer to obtain economic and efficient transmission asset costs. We will keep the efficiency of Developer procurement and contract management approaches under review for future cost assessments.

1.25. When undertaking the assessment of costs to derive the FTV, we review updated information provided by the Developer. Where Capex or development costs have increased since the ITV, the Developer is asked to provide supporting documentation to justify these increases. We may undertake a technical investigation which focuses on, for example, a particular cost component, such as an increase of costs in a contract or multiple increases across several contracts.

2. WMR Cost Assessment

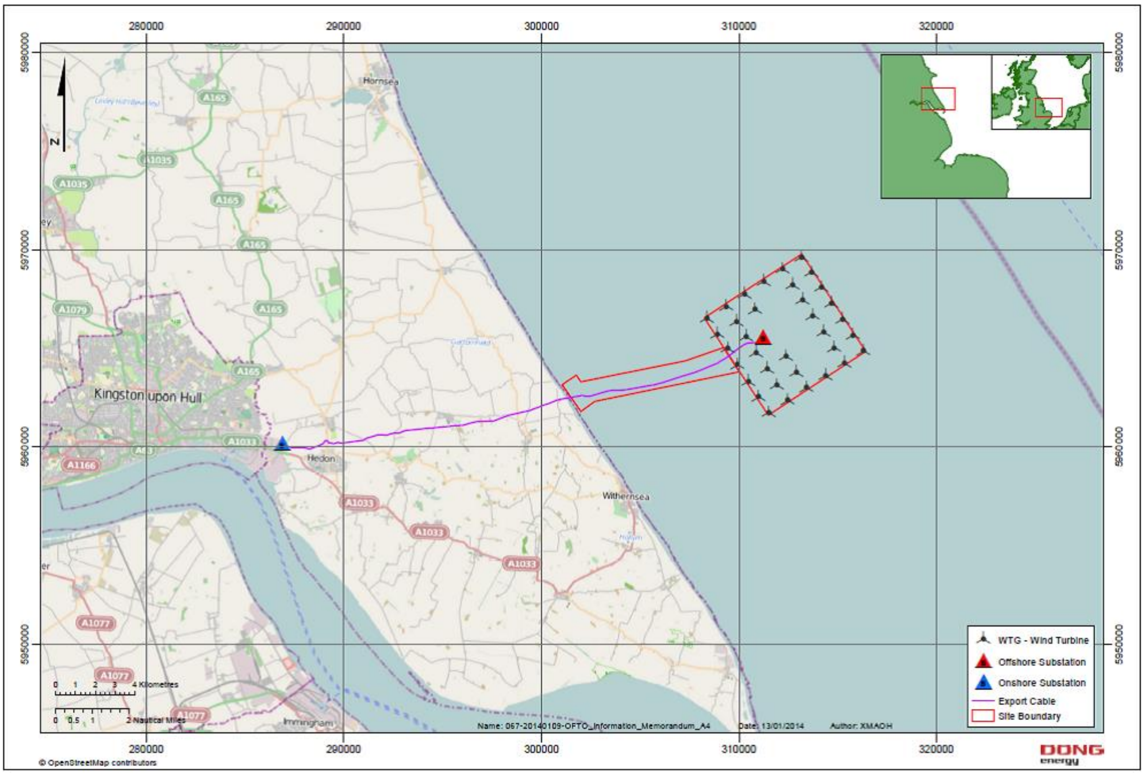
Chapter Summary

This chapter summarises how we have undertaken our cost assessment for the WMR transmission assets from the initial transfer value to the final transfer value. It provides a breakdown of the key cost categories that we have considered and highlights the decisions that we have made.

WMR Transmission Assets

2.1. The WMR Wind Farm is located in the North Sea, approximately 8.0km off the coast of Yorkshire, as shown in Figure 1 below. The WMR Wind Farm consists of 35 6MW wind turbine generators, with a maximum output of 205MW at the OFTO point of connection to the onshore system[3].

Figure 1 – Location of the WMR Wind Farm and Transmission Assets



[3] The maximum possible output of the windfarm is 210MW at the offshore platform. A maximum output of 205MW is allowed to be exported to the OFTO point of connection to the onshore system. The difference is attributed to array cable losses. See page 2 of the PIM

2.2. The WMR Wind Farm is owned and financed by Westermost Rough Limited, jointly owned by DONG Energy A/S (50%), Marubeni Corporation (25%) and UK Green Investment Bank plc (25%) (collectively 'the Developer').

2.3. The WMR transmission assets connect to the WMR Wind Farm at one offshore platform. The transmission assets that are transferring to the OFTO comprise:

- One offshore platform and associated electrical equipment;
- One subsea export cable of approximately 12km;
- One onshore cable of approximately 15km; and
- One onshore substation at Hedon (and two 275kV Switchgear bays within the existing NGET Hedon substation).

2.4. The boundary points for the WMR transmission system are defined below:

- Offshore: Located at the 150/34kV transformer 34kV Low Voltage terminals; and
- Onshore: Located at the interface flanges/gas barriers between busbar selector disconnectors owned by WMR and NGET busbars contained within the existing NGET Hedon 275kV substation.

2.5. The spares included in the transmission assets that are transferring to the OFTO are:

- A length of subsea cable;
- Various joints (transition, straight and cable repair joints);
- Cable terminations; and
- Other miscellaneous spares.

WMR cost assessment process overview

2.6. We received the first cost information from the Developer in November 2013. We have worked with the Developer and our advisers to reach an assessment of the costs which ought to have been incurred in connection with the development and construction of the transmission assets. Set out below is an outline of the steps taken in the cost assessment process for the Project.

- February 2014: Initial transfer value (£199.5m) published.
- October 2014: Indicative transfer value (£172.3m) published.
- November 2014 – July 2015: Cost reporting updated by the Developer over the course of the construction of the project.
- July 2015: Forensic accounting and technical investigations for FTV undertaken.
- August 2015: Final cost reporting update (including reallocation of Capex from development) and final supporting information received from the Developer.

- October 2015: Draft cost assessment report released to the Developer for comment and the preferred bidder for information.
- December 2015: Draft cost assessment report published alongside the section 8A consultation.
- February 2016: The Authority determines the final transfer value when it determines to grant the licence to the successful bidder. The final cost assessment report is published after licence grant.

Summary of indicative transfer value determination

2.7. The initial transfer value calculated in February 2014 was £199.5m. This value was based on information received from the Developer at an early stage in the construction and development of the Project. A number of the Developer's contracts were in the process of being finalised at the initial transfer value stage and these were considered in greater detail when the indicative transfer value was set.

2.8. The indicative transfer value of £172.3m was established in October 2014. Our estimate was supported by our forensic accounting advisors, Grant Thornton ("GT"), our internal analysis and the supporting information provided by the Developer.

2.9. When we set the ITV we reduced the Project's export cable supply costs by £2.9m and onshore substation electrical costs by £3.2m. These reductions were informed by benchmarking analysis undertaken at the time. We agreed to revisit these reductions at the FTV stage if the Developer provided sufficient substantiation to justify inclusion.

Process for determining the assessed costs

Accuracy and Allocation

2.10. The Project was constructed on a multi-contract basis. A forensic accounting investigation was undertaken by GT to ensure that the costs reported to us by the Developer were accurate, in that they represented the actual costs incurred by the Developer during the development and construction of the Project.

2.11. This investigation considered the main contracts in respect of the transmission assets for the following:

- The offshore substation and platform;
- The offshore cable supply and installation;
- The land cable supply and installation;
- Onshore civil engineering works; and
- Onshore connection costs.

2.12. We also checked that the costs were allocated to the correct asset category, in particular between generation assets and transmission assets. To assess whether the costs were allocated correctly we took into consideration the following:

- Metrics used when allocating costs between generation and transmission;
- The Developer's submissions using our cost reporting template;
- The findings of the forensic accounting investigation; and
- Cashflow payments related to the transmission assets.

Efficiency

2.13. After costs had been appropriately identified and allocated, we performed an assessment of whether these costs had been incurred economically and efficiently. This involved an internal benchmarking review and a technical investigation undertaken by our advisors.

Summary of assessment

2.14. Following completion of the development and construction of the transmission assets, the Developer submitted costs amounting to a proposed final transfer value of £168.9m. Our assessment of the economic and efficient costs which have been or ought to have been incurred, in connection with developing and constructing the transmission assets, has established a final transfer value of £156.7m. Table 2 below provides a breakdown of the cost categories for the Project at each stage and change between the indicative transfer value and the final transfer value.

Table 2: Summary of cost categories

Category	Initial Transfer Value February 2014 (£m)	Indicative Transfer Value October 2014 (£m)	Final Transfer Value August 2015 (£m)	Reasons for change between Indicative Transfer Value and Final Transfer Value
Capex	136.9	100.0	122.3	Overall increases of: £11.3m for reallocating costs from development; £2.9m in export cable supply costs not included in the ITV; £3.2m in onshore substation electrical costs not included in the ITV; £0.5m in foreign exchange losses; £9.1m in onshore substation, offshore substation and export cable construction costs. Offset by decreases of: £1.5m in onshore civils works due to deemed efficiency; £1.0m due to reallocation to operational and maintenance costs; £0.8m for reallocating costs from the transmission assets to generation assets; £1.4m for removing offshore platform and export cable installation costs not incurred.
Development	30.7	48.4	23.1	Decreases of: £11.3m for reallocating costs to Capex; £6.5m for removing estimated costs not incurred; £0.7m in consenting costs due to deemed inefficiency; £3.9m in project management costs due to deemed inefficiency; £1.5m due to reallocation to post energisation costs; £1.4m for adjusting the metric used to allocate costs between the generation and transmission assets.
Contingency	19.5	10.0	-	Contingency in the Indicative Transfer Value was used to address additional Capex and development costs. Unused contingency was released.
IDC	12.4	12.0	9.0	Decrease of: £3.0m due to cash flow adjustments in respect of reduced Capex and applying correct IDC end date.
Transaction	-	1.9	2.3	Increase of: £0.4m due to transaction budget increase.
Total	**199.5**	**172.3**	**156.7**	

2.15. The issues we have considered in setting the final transfer value are detailed below.

Capex

2.16. The Capex element of the final transfer value is £122.3m. Overall the Capex has increased by £22.3m from the indicative transfer value to the final transfer value. As discussed in more detail below, the increase is largely due to reallocating costs from development to Capex; reinstating Capex removed at the ITV stage; and an increase in construction costs. This is offset by reductions reflecting inefficiently incurred costs; the reallocation of costs to generation assets and the removal of costs not incurred.

2.17. GT undertook a forensic investigation of a selected number of Capex contracts. The main Capex contracts investigated were:

- STX France - supply of the offshore platform;
- Seaway Heavy Lifting – installation of the offshore platform;
- LS Cable & Systems - supply of the offshore, export and spare cable; and
- Visser & Smit Marine - installation of the offshore cable.

Accuracy and allocation of Capex costs

2.18. For the majority of Capex costs incurred on the Project, it was clear whether they should be allocated to the transmission or the generation assets in their entirety. For costs shared between generation and transmission assets, the Developer allocated certain proportions to the transmission assets using cost allocation metrics, which differ depending on the nature of the work undertaken. Only those costs related to the transmission assets were allowed in the final transfer values.

2.19. In conducting our own analysis of these costs there were a number of items whose accuracy and allocation we have discussed with the Developer. These items are set out below.

<u>Exchange rate movements</u>

2.20. A number of contracts, for example, the supply of transformers by GC Electric Systems, the supply of the offshore platform by STX and cable installation by VSMC were denominated in either Euros or Danish Krone. Total exposure amounted to €82.4m and DKK89.5m.

2.21. In accordance with the cost assessment principles set out in the Guidance, if a Developer has hedged its foreign currency contracts, the payment of their contract should then be based on such fixed rates and we will use that hedge rate for determining costs. The Developer managed the exposure to foreign exchange movements through forward exchange rate hedges, which were entered into in December 2012 when the Project received final investment approval.

2.22. In its final cost submission the Developer included additional foreign exchange losses for £2.6m under transaction cost items. These losses were subsequently re-allocated to Capex.

2.23. We reviewed the Developer's foreign exchange dealings to ensure that these were calculated correctly. As a result of this review, we reduced the Developer's claim for further exchange losses from £2.6m to £0.5m.

Ofgem's views

2.24. We agree that it was appropriate for the Developer to manage its foreign exchange exposures through the use of forward rates. We have concluded that the additional losses were calculated correctly in the Developer's revised submission. Therefore, for the purposes of the FTV, we have included £0.5m for additional foreign exchange losses.

Offshore Platform paint repairs

2.25. The Developer's cost submission included a cost of £1.0m for Offshore platform (OSP) paint repairs. The Developer explained that during OSP installation minor damage was caused to the OSP surface protection paint due to a variety of activities, for example, welding the topside to the jacket. Following OSP installation, the export and the Project's generation array cables were pulled in, stripped and terminated. This activity involved the use of cable winches which caused additional damage to the OSP paintwork on the cable deck, handrails and platform access stairs.

Ofgem's view

2.26. We consider that it was appropriate for the Developer to undertake these repairs. However, we note that a proportion of the post installation damage was due to pulling in the Project's array cables which is an activity that is not related to the development and construction of the transmission assets. Therefore, we have applied the allocation rate agreed at the ITV stage for sharing costs between generation and transmission. This has resulted in the removal of £0.8m from the Developer's final cost submission.

Operation and Maintenance (O&M) costs

2.27. The Developer's cost submission included £1m of costs in relation to onshore substation O&M activities that it planned to carry out prior to the assets being transferred to the OFTO.

Ofgem's view

2.28. Following discussions with the Developer, it confirmed that the proposed O&M costs are related to the interim maintenance of the Project's onshore substation. The assessed costs should cover development and construction costs only. Therefore, the Developer agreed that the cost should be removed. We have removed £1m from the Developer's cost submission.

Efficiency of Capex costs

2.29. The Developer's final cost submission included a number of increases in Capex costs. These related to costs which had been disallowed at the ITV stage and additional construction activities.

2.30. For the purposes of informing our assessment of the efficiency of the project's Capex costs, we asked our technical consultant Xero Energy ("consortium between Xero Energy Ltd and Offshore Wind Consultant Ltd") to carry out a detailed investigation of the Project's Capex costs. In particular, our technical consultant was asked to investigate, amongst other things, the project's approach to transmission asset design, contract procurement, project management costs and whether the Capex costs submitted were within the expected range.

2.31. The findings from the Xero technical review have been used to inform our assessment of the efficiency of the Project's development and Capex costs. We have detailed below the main issues that were considered and how we have assessed these costs.

Capex disallowed at ITV

2.32. The Developer's final cost submission included £6.1m of Capex costs which had been disallowed at the ITV stage.

<u>Onshore substation electrical costs</u>

2.33. At the ITV stage, following a benchmarking review we considered onshore substation electrical costs too high for a project of this size and complexity. There was insufficient information from the Developer to justify the inclusion of these costs. Therefore, we removed £3.2m from the Project's onshore substation electrical costs. However, we agreed to review this decision during the FTV stage if additional information was provided to substantiate the level of costs proposed.

2.34. Our advisor reviewed the onshore substation electrical costs and noted that the Project required additional electrical assets due to design changes. These changes were outside the control of the Developer as they were due to the late provision of system information by NGET. Xero undertook a cost review and concluded that the substation electrical costs, given the design changes, were within their expected cost range.

Ofgem's views

2.35. Following the review undertaken by our advisor we have concluded that it was appropriate to revisit the estimate made at the ITV stage and following a detailed review of all information provided we have accepted the additional justification provided by the Developer and have included the £3.2m in the FTV. We consider that this represents the economic and efficient costs for the project's onshore substation electrical costs. This revised position represents a £3.2m variance to the ITV Capex position.

<u>Export cable supply costs</u>

2.36. At the ITV stage we removed £2.9m from the Project's export cable supply costs. In setting the final transfer value, additional work was undertaken to consider the Developer's supporting evidence.

2.37. We asked our advisor to review the Project's export cable supply costs. Xero investigated the cable design specification, the Developer's approach to procurement and undertook a cost review. Xero noted that the Developer followed a competitive tender process and that the export cable supply costs were within the expected range. The Developer provided additional information and explained that a number of European cable suppliers were unwilling to tender for the cable supply contract, therefore, the Project decided to source its cable from South East Asia. This resulted in higher transport costs which accounts for the level of costs submitted by the Developer.

Ofgem's views

2.38. Following the review undertaken by Xero and careful consideration of the justification provided by the Developer, we have included the additional £2.9m in the FTV.

Capex increase since ITV

2.39. In its final cost submission the Developer included a Capex increase of £9.1m. These costs relate to the Project's onshore substation civil works, the offshore platform and supply and installation of the export cable. Our views on whether these increases have been incurred in an economic and efficient manner are discussed below.

2.40. It should be noted that following a review of the cost submitted by the Developer, £11.3m of costs were reallocated from development to Capex. For the purpose of setting the final transfer value, we reviewed the Project's revised Capex value to ensure these costs were economically and efficiently incurred.

<u>Onshore substation costs</u>

2.41. The Developer submitted increased Capex costs associated with the onshore substation civils works. The Developer entered into a contract for the provision of onshore substation civil works, at a cost of £5.2m. The Developer submitted a cost of £10.2m in its final cost submission, i.e. an overspend of £5m. Our advisor reviewed the events leading to the project overspend and indicated that during the construction period a large number of Variation Orders (VOs) were raised by the contractor. The VOs covered costs arising from civil design changes, construction delays and changes to the scope of contracted work. The sections below set out our position on these cost increases.

Onshore substation civils design

2.42. Costs increased by £1.5m due to delays in finalising the Project's onshore civils design. Xero investigated the reason for the delays and noted that the Project's electrical design was not concluded until additional information was provided by

NGET. This was provided at a late stage in the process, therefore, the Developer incurred extra costs to finalise its civils foundation design.

Ofgem's views

2.43. We investigated the factors that led to the design delays and reviewed additional evidence that was supplied by the Developer. Based on the information provided, we are satisfied the delays were largely attributable to electrical design changes mandated by NGET and recognise the Developer had limited control over this factor and reacted appropriately. Therefore we have accepted the additional civils design costs and have included this additional £1.5m into the final transfer value.

Onshore substation construction delays

2.44. The Project faced a number of construction delays in respect of the onshore substation due to additional works required on site, for example, demolition and soil contamination works. A number of VOs were raised by the civils contractor to deal with these works. Three VOs were construction acceleration payments, totaling £1.5m.

2.45. Our consultant investigated the background to these construction delays and concluded that the construction acceleration costs could have been avoided. The delays were due to the Developer failing to secure land rights for the original onshore site, which led to the Developer needing to secure an alternative onshore substation site at short notice. Xero suggested that the acceleration costs should be removed from the final transfer value.

Ofgem's views

2.46. In addition to taking advice from Xero, we considered further representations directly from the Developer to explain the reasons for the cost increase. The Developer explained that it had not secured land rights to its original onshore substation site due to a failure to agree commercial terms in an acceptable time, and therefore was required to source an alternative site at short notice.

2.47. The Developer argued that it acted prudently and chose to incentivise its contractors by paying construction acceleration payments to keep construction on track and to mitigate the possibility of delays offshore. While we recognise the risks faced by the Project, we are of the view that these costs were avoidable and could have been avoided if the selection of the original site was managed efficiently. We do not consider the acceleration payments to be an economic and efficient spend. Accordingly, we have removed £1.5m from the Developer's submission.

2.48. We have also reviewed the remaining VOs raised by the onshore civils contractor in connection with onshore substation civil works. We concluded that those costs were efficiently incurred. Therefore, we have included the increased expenditure in the Project's final transfer value.

Development costs

2.49. The assessed development expenditure for the WMR transmission assets is £23.1m. These are costs incurred by the Developer outside the scope of the main construction contracts.

2.50. For the purpose of informing our cost assessment, we have reviewed the cost information provided by the Developer in connection with developing the Project. We have also asked our advisors to investigate the Project's development costs.

Accuracy and allocation of development costs

2.51. At the ITV stage following discussions with the Developer a reallocation exercise was undertaken. When the Developer provided their final cost submission, development costs were estimated at £40.5m; this represents circa 23% of the Project's total cost submission. We were concerned by the level of these costs as they appeared well above what we have observed on other projects. This would have resulted in a significant cost reduction. Following further discussions with the Developer, we agreed that additional analysis should be undertaken to substantiate these costs to understand whether project specific factors may account for the cost levels. The Developer also took an exercise to check whether the development costs inappropriately included Capex.

<u>Reallocation to Capex</u>

2.52. Following a further review of its submission, the Developer confirmed that the cost of commissioning the transmission assets, along with a number of other Capex costs, had been allocated to development. The Developer provided further analysis which proposed a reallocation of £16m of costs from development to Capex.

Ofgem's view

2.53. Following review of the proposed reallocations provided by the Developer, we agreed that £11.3m of this was Capex. We rejected the re-categorisation of £4.7m of consenting and travel and meeting costs since we consider such costs to be development activities in line with our Guidance. In addition, we conducted a further review of Capex in order to assess the impacts of the re-categorisation on the level of costs submitted. Whilst we observed some increase across the Project's Capex, we are satisfied costs remain at a level that is acceptable for a project of this size and complexity.

<u>Post-energisation costs</u>

2.54. The Developer's final cost submission included £1.7m of costs associated with activities that have been (or will be) carried out in the period when the transmission assets are in service and operational. The categories of costs include, amongst other things, fishery disturbance payments, crop loss compensation payments and onshore substation leases. In some cases, the costs proposed were claimed beyond 2014.

Ofgem's view

2.55. Following discussions with the Developer, we received supporting information indicating that these costs were related to minor construction activities that were carried out until the end of November 2014. We have allowed the inclusion of these costs until this point. Costs proposed beyond November 2014 have been removed from the FTV as our cost assessment covers development and construction costs only. As a result, we have removed £1.5m from the Developer's final costs submission.

Efficiency of Development Costs

Onshore substation site consenting costs

2.56. The Developer obtained consent for in total four sites for its onshore substation at a cost of £1m. These costs were incurred between 2008 and 2012. A programme for the project was to have a consented and secure onshore substation site in place prior to October 2012.

2.57. The Developer identified a site located on land adjacent to NGET's substation at Hedon as the preferred location for the onshore substation. The Developer obtained consent for the site but did not seek formal confirmation with the landowner to secure land rights. In early 2012, the landowner notified the Developer that it could no longer use the land. In the absence of the secured land rights, this posed a significant risk for the Project.

2.58. The Developer decided to consent additional sites in a short space of time. In July 2012, planning applications for the alternative sites was lodged with the relevant authorities. The Developer subsequently chose a preferred site. As discussed in the previous section, the siting difficulties led to construction delays and additional costs, with access to the onshore construction site being delayed from January to March 2013.

Xero's views

2.59. Xero reviewed the events that led to the increased costs and the process followed by the Developer.

2.60. Xero noted concerns with the Developer's approach. With regards to the original site that was progressed by the Developer, Xero noted that the Developer consented only one site in isolation. Xero suggests that it is good practice to progress at least two options, a main and a reserve, to mitigate risks that may arise during development; for example, failed land ownership negotiations or planning difficulties. Xero also noted concerns with obtaining planning permission for three additional sites.

2.61. Xero concluded that consenting four sites was not an efficient spend and resulted in increased costs. Xero concluded that £0.7m from the Project's development costs should be removed, as in their opinion, these were inefficiently incurred costs.

Ofgem's views

2.62. In addition to taking advice from Xero, we considered representations directly from the Developer. The Developer explained that it did not secure land rights for the original site. The Developer added that it had to secure an onshore substation site in a timely manner to avoid delaying construction. The Developer chose to progress three additional sites to support land negotiations and increase the chance of securing a suitable site.

2.63. We recognise the need for the Developer to minimize construction delays and that it was necessary to secure an alternative onshore substation site. However, the Developer did not fully risk assess the implications to the project if land rights were not obtained. The risk of the site falling away could have been foreseen at that time of securing land rights and many of the potential impacts mitigated in advance.

2.64. We are of the view that the costs incurred for consenting three additional sites is a direct result of the Developer not managing the consenting process efficiently. After careful consideration we have allowed the Developer to recover the costs of consenting one site only and we have removed the remaining consent costs. This has removed £0.7m from the Developer's final cost submission. We have allowed some of the additional consequential costs due to these siting delays in the FTV after the Developer demonstrated that they had been efficiently incurred.

Project Management (PM) costs

2.65. When the Developer submitted their final cost submission, project management costs were estimated at £17.9m.

2.66. We were concerned with the level of these costs and asked our advisor to investigate whether the level of costs submitted was reasonable. Xero concluded that the PM costs were not in line for a Project of this size and complexity. The expected range proposed by Xero is between £9.1m and £11.6m, with an average value of £10.8m.

2.67. For the purpose of informing our assessment of costs, we requested additional information from the Developer. The Developer provided further analysis which resulted in costs being reallocated to Capex. With respect to project management costs, the Developer proposed a final cost position of £14.8m.

Ofgem's view

2.68. We compared the Developer's submission against projects of a similar size and nature and we considered that the submitted costs were not in line for a project of this size and complexity. The Developer argued that additional PM was required to manage Project delays, for example, quality assurance and Health and Safety; in particular, those arising from changes to the Project's onshore substation design and complexities linked to the manufacture of the Project's Offshore Platform. We understand that these two events only account for a £0.1m increase in PM costs. The supporting evidence provided by the Developer indicated that these matters were outside the control of Project and unavoidable costs; therefore, we have accounted for these costs in the FTV. However, when taking into account these specific factors, they do not justify the high level of costs submitted.

2.69. We note that the Developer's preferred approach is to multi contract and project manage all interfaces. The Developer's rationale is that this is more efficient and cost effective when compared to an Engineering Procurement and Construction (EPC) type approach. However, our review which considered the level of PM costs for other projects of this size and complexity and which were managed on a multi-contract basis indicated that the Project's PM costs should be in line with the average of the range proposed by our advisor. Accordingly, £3.9m has been removed from the Developer's final transfer value submission.

Contingency

2.70. The assessed costs do not contain a separate contingency value. £10m of the contingency that existed at the indicative transfer value stage has primarily been utilised to deal with the problems incurred during construction of the onshore substation site. The remaining was removed by the Developer from its final cost submission.

Interest during construction

2.71. The total IDC calculated for the WMR transmission assets in the assessed costs is £9m. We reviewed the Developer's IDC submission which has resulted in a number of IDC changes. The net impact of these changes was a £3m reduction from the IDC component of the ITV.

Accuracy and allocation of IDC

2.72. Following receipt of the Developer's final cost submission, we discussed the operational status of the transmission assets with the Developer. We noted that the Developer had requested IDC for the period up to the end of August 2014, despite the assets being in service and operational since the middle of the month. IDC can only be recovered for financing costs incurred by a Developer in the period of developing and constructing the transmission assets. In line with our Guidance, IDC cannot be recovered for partial months as it is calculated on a whole month basis. As the Project became operational in mid-August 2014, we instructed the Developer to adjust the submission and remove the IDC claimed for that month. This resulted in a reduction of £0.9m.

Efficiency of IDC

2.73. Further changes were made to the IDC calculation to reflect cash flows relating to the costs allowed at the FTV stage. This reduced the IDC amount relative to the ITV position by a further £2.1m.

Transaction costs

2.74. The indicative transfer value contained an estimate of the transaction costs of £1.9m at that time. The Developer has subsequently submitted a firm estimate of the transaction costs they expect to incur to asset transfer. We have reviewed this estimate and assessed transaction costs at £2.3m.

Accuracy and allocation of transaction costs

2.75. Transaction costs included in the Developer's final costs submission were estimated at £5.4m. We noted that this included £3.1m of Forex losses incurred by the Developer.

Ofgem's view

2.76. We consider exchange losses as Capex. Therefore, we have re-allocated the £3.1m exchange losses to the Capex section and considered it there.

Efficiency of transaction costs

2.77. Following reallocation of exchange losses, transaction costs increased by £0.4m since the indicative transfer value. The Developer explained the increase is largely due to the transaction budget being revised up to account for more resources been needed to reach asset transfer.

Ofgem's view

2.78. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. We have considered the types of resource costs incurred in relation to this Project's tender process and the level of transaction costs incurred appear reasonable in comparison with other projects.

Confirmations in relation to tax benefits

2.79. The indicative transfer value was calculated on the basis that the purchaser would obtain the full benefit of all available capital allowances. If this was not the case for the final transfer value we would reduce the assessment of costs for an amount that reflects the value of the tax benefit retained by the Developer. For the final transfer value the Developer has confirmed that the purchaser will be able to obtain the full benefit of all available capital allowances and therefore the final transfer value will be the same as the assessed of costs.

3. Conclusion

3.1. In conclusion, in accordance with Regulation 4 of the Tender Regulations, the Authority has assessed the economic and efficient costs which ought to have been incurred in connection with developing and constructing the WMR transmission assets is £156,717,151.

Appendices

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Appendix 1 - Glossary

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Authority

The Gas and Electricity Markets Authority

C

Capex

Capital Expenditure

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Developer

WMR Limited

Xero

A consortium between Xero Energy Ltd and Offshore Wind Consultant Ltd

G

GT

Grant Thornton

I

IDC

Interest During Construction

IM

Information Memorandum detailing the projects details released to QTT bidders through the tender portal.

ITT

Invitation to Tender

M

MW

Megawatt

MVA

Megavolt-Ampere

O

OFTO

Offshore Transmission Owner

P

Project

The development and construction of the WMR offshore transmission assets

PTRA

Post Tender Revenue Adjustment

Q

QTT

Qualification to Tender