

Offshore Transmission: Cost assessment report for the Barrow transmission assets

Draft Decision

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Overview:

This document sets out our cost assessment for the Barrow transmission assets. The key principles that we have applied in our cost assessment process for the first transitional tender round are also described. The assessment of costs will be used by the Authority to determine the value of the Barrow transmission assets to be transferred to the successful bidder.

The preferred bidder has incorporated the draft assessed transfer value into their TRS for purposes of the section 8A licence consultation and we do not expect any further changes to the assessed transfer value. However, we do not intend to finalise the assessed transfer value until the Authority has determined to grant an offshore transmission licence to the successful bidder.

Context

Ofgem and the Department for Energy and Climate Change (DECC) have developed a regulatory regime for offshore electricity transmission. A key part of this regime is that offshore electricity transmission licences will be granted to Offshore Transmission Owners (OFTOs) following a competitive tender process run by Ofgem. The transitional tender regime has been designed for projects that were under development, in construction or constructed at the time of the announcement of the regime¹.

The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010 (the Tender Regulations) provide the legal framework for the process which Ofgem will run for the grant of offshore electricity transmission licences. 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 in the transitional regime. The Tender Regulations provide for an estimate and 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 successful bidder.

At the time we commenced the cost assessment process, the transmission assets of the projects in the first transitional tender round, other than Barrow, were still under construction. For these projects we carried out an estimate of costs under the Tender Regulations before commencing the assessment of costs. As Barrow was operational at this time and the transmission assets were available for the use of transmission, we did not carry out an estimate of costs under the Tender Regulations, but commenced the assessment of costs from the outset.

Associated documents

- Offshore Transmission: Notice under section 8A(3) of the Electricity Act 1989 (Barrow) [Link](#)
- Offshore Transmission: Cost assessment report for the Robin Rigg transmission assets [Link](#)
- Offshore Transmission: Cost assessment report for the Gunfleet Sands transmission assets [Link](#)
- Offshore Transmission: Draft Cost assessment report for the Walney 1 transmission assets [Link](#)

¹<http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf>



Offshore Transmission: Cost Assessment for the Barrow transmission assets

- Ernst & Young report on Interest During Construction [Link](#)
- KEMA technical benchmarking report [Link](#)
- The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010 [Link](#)
- Offshore Transmission: Tender Rules [Link](#)
- Interest During Construction for Transitional Tender Rounds [Link](#)

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Executive Summary

This document sets out the assessment of costs which ought to have been incurred in connection with the development and construction of the transmission assets for the Barrow project and details the cost assessment process we have undertaken.

Key stages of the TR1 process for Barrow

The cost assessment process involved three key stages set out below.

- The initial calculation of costs for the Barrow project was £36.5m, which was communicated to the developer in July 2009 and published in the preliminary information memorandum in September 2009 (the initial transfer value);
- The initial calculation was updated as a result of further information and continuing analysis. The updated calculation, which was also £36.5m, was communicated to the developer in September 2009 (the indicative transfer value). The indicative transfer value was published in the project information memorandum; and
- At this stage of the cost assessment process we have reached a final decision on the assessment of costs of £33.6m (the assessed transfer value).

The Barrow project

The table below shows the movement between the initial, indicative and assessed transfer values, and the reasons for these movements.

Table 1: Summary of cost breakdown history

Category	Initial Transfer Value July 2009 (£)	Indicative Transfer Value Sept 2009 (£m)	Assessed Transfer Value July 2011 (£)	Reasons for change between Sept 2009 and July 2011
CAPEX	26.3	26.4	25.7	Better identification of costs (reallocation to development) plus a reduction of £0.3m to reflect the impact of contract variations
Development	3.0	3.0	3.5	Increase due to better identification of costs (reallocation from capex) during the forensic accounting investigation
IDC	7.2	7.1	3.0	The developers original IDC submission has been capped at 10.8% and runs to February 2006 only
Transaction	-	-	1.4	Transaction costs not assessable until the end of the cost assessment process
Total	36.5	36.5	33.6	The decrease is largely the result of the cap on IDC in respect of both rate and period of application

Capex

Table 1 shows that capex costs have altered slightly from the initial transfer value to the assessed transfer value. This resulted from changes made to the allocation of costs between generation and transmission assets as detailed in the developers total Engineer Procure Install and Commission (EPIC) contract value. This allocation change results from the forensic accounting investigation.

Development costs

The allocation of development costs to the transmission assets was originally based on the costs apportioned to the transmission assets in the EPIC contract. As with capex costs, one of the outcomes of the forensic accounting investigation was to alter this allocation which resulted in an increase in the level of development costs.

Interest during construction

Table 1 shows that interest during construction (IDC) has been reduced by £4.2m from the initial transfer value to the assessed transfer value. The majority of the reduction occurred because the transmission assets were completed and

operational in February 2006 and thus the period of application has been limited to this date.

In addition, a further reduction has resulted from changes to the interest rate used to calculate IDC. We have undertaken analysis (supported by our financial advisors) on the appropriate level of IDC based on information provided by the developers and taking into account the circumstances surrounding the investments made in the transmission assets of the first transitional tender round. This indicated that it was reasonable to impose a cap on IDC and that the appropriate range for a cap on interest rates was 9.4-10.8% on a pre tax nominal basis. Based on this analysis we have determined a cap of 10.8% to be appropriate which is applied to the Barrow project. This decision was communicated in a letter to the project developers in April 2010.

Transaction costs

The transaction costs are composed of both internal and external resource costs of the tender process for the developer as well as tender fees that the developer has paid to Ofgem through the tender process. We have checked these costs to ensure that they have been correctly allocated by the developer.

Confirmations in relation to tax benefits

The developer has confirmed that the incoming OFTO will be able to obtain the full benefit of all available capital allowances. Therefore, no reduction to the assessment of costs has been made.

Assessed transfer value for Barrow

The assessed transfer value of the Barrow project transmission assets is £33,557,558.

1. Cost assessment process for TR1

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 in the transitional regime. This chapter sets out the process we have followed in carrying out the TR1 cost assessment.

Overview of the TR1 cost assessment process

1.1. The Tender Regulations provide the legal framework for the process which Ofgem will run for the grant of offshore electricity transmission licences. This process includes assessing the economic and efficient costs of constructing and developing 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.
- 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.

Data collection

1.3. To undertake this exercise we have gathered and reviewed a range of information and supporting evidence. Detailed cost information was provided by developers in the form of cost reporting templates, contract values, asset cost schedules and cash flows. These relate to the actual/forecast costs of construction contracts and development costs related to the transmission assets being transferred to the successful bidders.

1.4. The data collection to inform the cost assessment process commenced in December 2008 and has continued to date. Throughout this period we have worked closely with the developers of the relevant offshore transmission assets. The information we have gathered relates to the following cost categories that are involved in the development and construction of the transmission assets:

- Capital expenditure
- Development costs

- Interest during construction
- Transaction costs.

1.5. Developers have also provided supporting evidence to substantiate their cost submissions including, amongst other things, contract documentation, supplier payment lists and asset schedules. We have been supported throughout this process by Ernst and Young as financial and KEMA as technical advisers.

Process stages

1.6. The cost assessment process for the first transitional tender round involves the key stages set out below.

Initial transfer value

1.7. The initial transfer value calculated in July 2009 was based on cost submissions by the developer of each project. This value was made available to bidders at the Pre-Qualification (PQ) stage of the tender process. The letter we sent to developers at this time indicated that this calculation might be updated as a result of any further information provided by the developer and our continuing analysis.

Indicative transfer value

1.8. In September 2009, we provided the indicative transfer value for the commencement of the Qualification to Tender (QTT) stage of the tender process. This value was also used for the tender revenue stream bids submitted by bidders at the Invitation to Tender (ITT) stage. The letter we sent to developers in September 2009 indicated that this calculation might be updated as a result of any further information provided by the developer and our continuing analysis. For projects where the transmission assets were not yet available for the use of transmission (being all projects other than Barrow), this letter also provided a guarantee (subject to certain matters) that the minimum transfer value they would receive for the transmission assets once their project was completed would be 75% of the indicative transfer value.

Assessed transfer value

1.9. Once the transmission assets are complete or are close to completion and the developer has indicated that they have documentation to support an assessment, we will commence an exercise to determine the assessed transfer value.

1.10. A draft of the cost assessment report, including the amount of the assessed transfer value, will be sent to the developer and the preferred bidder for the relevant project. This enables either of these parties to comment on the factual nature of the report prior to the cost assessment being finalised by Ofgem.

1.11. The assessed transfer value will then be incorporated by the preferred bidder into their tender revenue stream for the purposes of the section 8A licence consultation and we do not expect any changes to the transfer value after this point. The draft cost assessment report will be published alongside the Section 8A licence consultation. The assessed transfer value will then be confirmed once the Authority has determined to grant an offshore transmission licence to the successful bidder. After licence grant the final cost assessment report will be published on the Ofgem website.

Updated indicative transfer value

1.12. Where it is not possible for us to complete the cost assessment prior to the asset transfer we will determine what proportion of the indicative transfer value the developer should receive on transfer of the transmission assets. This may be greater than or equal to the 75% minimum transfer value referred to in 1.8. We will also consider whether the indicative transfer value itself should be updated in light of further evidence arising from our cost assessment process since the indicative transfer value was published.

1.13. The indicative transfer value (updated where relevant) will then be incorporated into the tender revenue stream of the preferred bidder for the project along with the relevant cash flow reflecting the staged payment of the transfer value to the developer.

1.14. Once final costs are known and the developer can provide documented evidence, we will proceed to finalise our cost assessment. The deferred consideration (being the difference between the assessed transfer value and the proportion of the indicative transfer value received by the developer on transfer) will then be paid by the OFTO to the developer and the Post Tender Revenue Adjustment (PTRA) mechanism in the licence will be used to reflect the assessed transfer value.

Cost assessment analysis for TR1

1.15. We have applied two tests throughout the cost assessment process.

Test 1 - Assessing the accuracy and allocation of developers cost submissions

1.16. As a first test, we have checked the accuracy of developers' data and the appropriateness of cost allocations, in particular, between the offshore generation and transmission assets. Throughout the cost assessment process developers have provided cost information to us on an ongoing basis. Where we have identified discrepancies in how developers have allocated these costs we have checked with developers to assess if they have been allocated to the correct asset category and made adjustments accordingly.

1.17. To support the cost assessment process we have also undertaken a forensic accounting investigation. The scope of this investigation was shared with developers in advance. This investigation was based on the final costs that the developer has provided to us and was applied to a sample of contract costs. The actual sample for each project varied due to the different contracting strategies

adopted by the developer and the specific needs of the project, but generally focussed on the most expensive contract and/or contracts which had material increases in costs such as export cable supply and installation contracts.

1.18. The forensic accounting investigation was undertaken primarily to validate the cost allocations provided by developers. This may have indicated the need for amendments to the developer's submissions to reflect, for example:

- the actual costs incurred (eg in respect of exchange rates on foreign currency payments)
- more relevant metrics for the allocation of shared service costs.

1.19. Where amendments were in our opinion required and in the absence of further evidence from the developer to substantiate the original allocation, we incorporated the recommended changes from the forensic accounting investigation.

Test 2 - Assessing if developer's costs are economic and efficient

1.20. Under test two we sought to assess through appropriate analysis whether the costs had been economically and efficiently incurred by the developer. Where possible, we have sought to apply benchmarking and where industry wide cost indices were unavailable we have reviewed data from other projects within the first transitional tender rounds. This analysis has included benchmarking across the projects (see 1.21 below) and analysis in relation to funding interest rates (see 2.14 - 2.20 below). We consider such approaches to be an important tool in assisting us in ensuring these costs are economic and efficient.

1.21. To help us calculate the indicative transfer value we undertook a benchmarking exercise using comparable costs across all projects in the first transitional tender round to identify any cost outliers across the main cost categories. Any cost outliers identified through the benchmarking exercise were then subject to further review. This exercise examined individual cost categories including:

- total cost of transmission assets as a percentage of overall project cost
- total cost of transmission assets per MW kilometre
- cost of offshore substation per secure MW
- cost of offshore substation (platform and electrical) per installed MW
- cost of submarine cable supply and installation per kilometre
- cost of transformer per MVA
- cost of reactive equipment per kilometre of cable
- development cost as a percentage of transmission assets.

1.22. This benchmarking exercise informed our communication to developers in our letter of September 2009 which set out the indicative transfer value.

1.23. We have also considered the procurement processes adopted by developers to obtain economic and efficient transmission asset costs. We have noted the differing procurement approaches taken by developers for the transmission assets in the first transitional tender round. We will keep the

efficiency of developer procurement and contract management approaches under close review for future cost assessments.

1.24. Where CAPEX or development costs have increased since the indicative transfer value was set, developers have been asked to provide supporting documentation to justify why these increases occurred. Depending on the nature of the increase, we have undertaken a technical investigation which focussed on, for example, a particular cost increase in a distinct contract or multiple increases across several contracts.

2. Cost Assessment principles

Chapter Summary

This chapter sets out the cost assessment principles we have adopted in determining the assessed transfer value for the first four projects within TR1 (Barrow, Robin Rigg, Gunfleet Sands and Walney 1). We intend to apply these principles in our cost assessment process for other projects in TR1. However, we may need to vary them or apply additional principles where appropriate in light of the analysis undertaken in respect of such projects.

Introduction

2.1. This chapter sets out the cost assessment principles we have adopted in relation to various cost categories for TR1 and the reasoning for such principles.

2.2. The principles set out in this chapter are:

- allocation of costs
- economically and efficiently incurred costs
- interest during construction
- treatment of contingency
- spares
- tax - VAT
- tax - capital allowances
- depreciation of operational projects
- transaction costs
- exchange rates
- outstanding costs
- capitalisation of operating costs.

Allocation of costs

Capital expenditure

2.3. On all projects, there were some costs submitted by developers that have been split between generation and transmission. An example of this is where the cable installation contract covers both the export cables (transmission) and the inter array cables (generation) or if seabed surveys cover the entire wind farm. In such instances we have requested the allocation methodology and metrics that the developer has used to determine what proportion of the costs have been allocated as transmission costs. Such a methodology may be based on the relative proportion of direct equipment costs (ie excluding all shared costs) for the transmission assets compared to the project as a whole. We have then cross-checked if the allocation of cost was based on the methodology and considered the metrics applied in order to ensure accuracy.

Development costs

2.4. Developers submitted a range of differing development costs, for example, the cost of undertaking design studies, seabed surveys, project management, costs related to gaining consents and the cost of acquiring the development rights from another party.

2.5. With support from our technical advisers we have analysed developers' initial cost submissions for development costs. At the time of this work our analysis showed that the range of development costs represented a high percentage of the total project costs (excluding financing). Our advisers have indicated that development costs typically represent between 10-15% of capital expenditure (for projects in the first transitional tender round). In calculating the assessed transfer value we have reviewed whether development costs are broadly in line with the range provided by our advisers. Where these differ markedly we have undertaken additional analysis to ensure that only appropriate development costs are allowed.

2.6. Given the wide range of different costs submitted across projects, it is important that these costs are allocated appropriately. We have required developers to identify these cost allocations. In some instances, costs have been identified that are more appropriately classified into other cost categories. Where this is the case developers were required to reallocate them.

Economically and efficiently incurred costs

Capital expenditure

2.7. Offshore transmission development and construction is a relatively new industry in which industry wide cost indices are not yet readily available. In order to assess whether the CAPEX totals proposed by developers were economically and efficiently incurred, we initially undertook a benchmarking exercise across all projects included in the first transitional tender round. This benchmarking exercise covered each of the main components of the transmission assets (ie cables, transformers, reactive equipment and onshore and offshore substations) and on an overall basis (eg cost per MW and/or as a percentage of the overall project including generation). Where any item of cost appeared to be an outlier above the norm, we carried out further investigations with the developer to assess if the costs were incurred on an economic and efficient basis.

2.8. Where expenditure on any main cost category or development costs had risen by a material sum since the indicative transfer value, further work was undertaken by our technical advisers to specifically review such cost items.

2.9. Together with the benchmarking data, we have noted the procurement and contract management approaches adopted by developers for the transmission assets. At this stage in the first transitional tender round we have decided not to apply a cap to any items of capital expenditure based on benchmarking as there has not been evidence to suggest that costs incurred are not economic and efficient. Instead we have focussed on the assessment of whether material cost increases are economic and efficient. However, we will keep this approach under

review during TR1 and beyond as more data becomes available from completed projects.

Development costs

2.10. The development costs provided by developers may not be easily attributable to either the generation or transmission construction activities as they relate to the process of developing and constructing the offshore project (generation and transmission assets). We have therefore focussed our analysis on ensuring the allocation proposed by the developer is appropriate and that we have clarity on the reasons why costs may have changed during the cost assessment process.

2.11. At the indicative transfer value stage we compared the proportion of total costs represented by development costs on each project in order to identify specific areas for further review across all projects. At this stage in the first transitional tender round we have not applied a cap to development costs based on benchmarking as we have no evidence to suggest that these costs for projects in TR1 are not economic and efficient. However, we will keep this approach under review during TR1 and beyond as more data becomes available from completed projects.

Changes in ownership

2.12. Many of the projects in the first transitional tender round have undergone changes in ownership (ie the original developer has sold the rights arising from initial development) in the period from the initial award of the Crown Estate lease up to the completion of the transmission assets. The shareholdings in some projects have been amended during the period in which the cost assessment has been undertaken. The total acquisition cost paid by the purchaser 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 assessed transfer value. This may require the developer to use an appropriate allocation metric to split such costs between transmission and generation. In checking that overall development costs are within an appropriate range (as set out in 2.5) this also provides a check that the costs incurred are appropriate, in light of project specific circumstances.

Interest during construction

2.13. IDC refers to the financing costs incurred by a developer in the period of developing and constructing the transmission assets. The total IDC for a project is driven by four key variables each of which needs to be economic and efficient. These are set out below and discussed in detail in the following sections:

- interest rate applied to the project
- duration of the financing
- cost items to which interest was applied
- the cash flow curve.

Interest rate

2.14. We have calculated IDC on a pre-tax nominal basis. The use of a pre-tax rate ensured that developers received a rate that enables them to meet the expected level of tax in the chargeable gain arising from the inclusion of financing costs in the assessed costs. This use of a pre-tax nominal basis is consistent with practice in onshore transmission price controls on reasonably incurred additional outlays not covered by the scope of the preceding price control.

2.15. For calculating the total IDC, developers were initially requested to provide cash flow information and the interest rates signed off on their project, supported by relevant internal (ie board level) documentation to verify the applicable rates. The first responses from developers were based on the rates sanctioned as part of their financial commitment to the project. These were used in calculating the indicative transfer value. We carried out further analysis on the interest rates for projects in the first transitional tender round and wrote to developers in April 2010 with the results.

2.16. This further analysis was required as the developers had provided a wide range of interest rates to be considered for the purposes of IDC and we were not convinced that the variation could be explained by underlying economic factors. Given the wide range of interest rates proposed, we considered what an appropriate cost of financing for such assets should be and whether there were reasonable grounds to impose a cap on the interest rate. In the absence of comparable benchmark data from other projects we decided to use appropriate wider industry data as explained below. We used our own internal assessment in conjunction with a report by our financial advisers to come to a conclusion on the appropriate cost of financing. The period considered by our financial advisers for their assessment of funding costs was 2005 to 2009.

2.17. As part of our assessment of appropriate interest rates, a number of factors were considered. Other than the first project completed (Barrow), the remaining projects in the first transitional tender round have largely been constructed and financed in the credit crunch period. The relative impact of the credit crunch reduced liquidity in the period examined. This meant that in general only the large integrated energy companies were able to develop and finance offshore wind farms at this time. Consequently these were the best comparators. These companies achieved gearing and beta levels indicated by our advisors. Other forms of funding were largely unavailable.

2.18. The E&Y report concluded that the range of interest rates for the upper end of appropriate financing costs was 9.4-10.8%. Given the impact of the credit crunch, the gearing and beta levels and the fact that other forms of financing were largely unavailable and for consistency across projects funded in the same period, we concluded that adopting the top end of the range would be appropriate. In April 2010 we wrote to the developers whose project interest rates were above 10.8% to inform them that, based on our analysis at that time, their rates were to be capped at 10.8%.

2.19. Where the developers provided evidence of a rate below the cap, their proposed level of interest rate has been used.

2.20. We noted in 2010 that the liquidity of funding for projects improved. The level of debt available for prospective bidders for the transmission assets provides an illustration of this. Where project delivery programmes are delayed such that the majority of project funding falls outside the period examined by our advisers we may consider reviewing the appropriate interest rate cap for such TR1 projects.

2.21. We recently published a consultation on IDC² which sets out our minded-to position on changing our approach to IDC. The closing date for consultation responses is 12 August 2011. We will review our approach to IDC (the rate, the cap and the date) from time to time and our approach to application may change in the future as market information on potential funding costs changes.

Duration of financing

2.22. Regulation 4 of the Tender Regulations provides that the Authority must calculate the economic and efficient costs of developing and constructing the transmission assets. For the purposes of IDC, we consider that development and construction ceases once the transmission assets are commissioned. The commercial supply of electricity to the transmission system which follows commissioning also indicates that the assets are complete and operational.

2.23. Each transitional project developer will have a project specific commissioning programme for the assets that it is constructing. It is important to differentiate between commissioning activities that are associated with the transmission assets and the wind farm generation assets. Before generation assets can be fully commissioned, the commissioning of the transmission assets will need to have reached a stage that permits safe energisation of the transmission system and provides an offshore transmission system that is ready to transport electricity on a commercial basis. There may be occasions where transmission asset and generation asset commissioning activities occur in parallel.

2.24. With these distinctions in mind, we have determined that IDC should be allowed up to the point where the transmission assets have been constructed and are fit for use as a system, or as part of a system, for the use of transmission of electricity. Where projects are phased, IDC will cease at the completion of each individual phase in accordance with the same principles. If we consider there is evidence of inefficient and uneconomic delays in the construction or commissioning programme for the transmission assets, the period of applicability may be curtailed to reflect this.

2.25. 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 reflect this.

²<http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/Cons2011/Documents1/Offshore%20transmission%20-%20Interest%20during%20construction%20for%20transitional%20tender%20rounds.pdf>

Cost items to which interest was applied

2.26. IDC is only applicable to the cash flow that represents the capital expenditure and development costs. Where amendments have been made to the developers submitted cost information from either the allocation or efficiency test this has been reflected in the cash flow. This ensures that the IDC calculated for the transmission assets reflects the economic and efficient cost of developing and constructing the assets.

Cash flow curve

2.27. IDC is calculated on the actual cash flow which represents when payments were made against the contracts for developing and constructing the transmission assets. Some developers have sought to apply IDC to accounting data rather than their actual cashflows. This has not been used to calculate IDC as it does not represent the actual cost to the developer and includes non cash elements such as retentions, accruals for work completed and provisions. Where developers have provided accounting data or this has been identified during the forensic accounting investigation we have sought the correction information from the developer.

Treatment of contingency

2.28. For projects still in the design or construction phase, developers' cost data forecasts for the initial and/or indicative transfer values have tended to include contingency amounts to deal with future uncertainty over the actual cost and timing of construction. The assessed transfer values do not include any contingency because construction has been completed and all costs should be either settled or agreed with suppliers or the developer should have provided a firm estimate (eg on tender costs). As a result, contingency has reduced to zero for the assessed transfer value.

Spares

2.29. Where spares for the transmission assets are to be transferred to the OFTO then we will allow them as part of the assessed transfer value, provided that they can be demonstrated to be economic and efficient.

Tax - VAT

2.30. HMRC have 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). HMRC have 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.

Tax - capital allowances

2.31. Each transfer of assets from a developer to an OFTO under the transitional tender round is for a set of assets on an as-built basis, based on actual expenditure. We have therefore assumed for the cost assessment process that the purchaser will obtain the full benefit of all available capital allowances and that the transfer value should be reduced where such benefits do not fully pass across. This position was referenced in our letter to developers in September 2009. The indicative transfer value has been calculated on the basis that the purchaser obtains the full benefit of all available capital allowances. 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 preferred bidder), which results in the purchaser 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.

Depreciation of operational projects

2.32. There are some projects in the first transitional tender round that have been operational for a period of time prior to the assets being transferred to the OFTO. We have considered depreciation in relation to such projects.

2.33. The design life indicated by manufacturers for offshore transmission assets is greater than 20 years. Therefore, at this stage in TR1 based on the assumption that the assets are capable of satisfying the 20 year life applicable to the revenue entitlement set out in the OFTO licence, and in the absence of evidence to suggest they will not do so, we therefore consider it reasonable not to apply depreciation to the assets. However will keep this under review and consider depreciation on a case by case basis.

Transaction costs

2.34. Transaction costs relate to the costs that the developer has had to incur as a result of the tender process. These can be split into two categories:

- tender fees
- developer's external and internal costs

Tender fees

2.35. Tender fees relate to the fees charged to the developer by Ofgem as part of its cost recovery methodology. We are including these costs as transaction costs in the assessed transfer value. This is consistent with the costs incurred in the development and construction of a set of assets that are being prepared for sale immediately following completion of construction.

2.36. Regulation 5 of the Tender Regulations set out that where the Authority has undertaken an estimate of costs under the Tender Regulations, the developer has to make a payment in accordance with the Authority's cost recovery methodology³ in relation to the Authority's costs in this respect.

2.37. Regulation 7 of the Tender Regulations sets out that the developer is required to make a payment in relation to the Authority's tender costs as calculated in accordance with the Authority's cost recovery methodology for that tender exercise. For the first transitional tender round, developers have been required to pay the Authority an administration fee of £50,000. This fee is considered to be a transaction cost and is recoverable by the developer.

2.38. Regulation 7 also sets out that developers are required to provide security in relation to the Authority's tender costs. For the first transitional tender round this was set on a sliding scale commencing at £500k per project. Developers were required to either provide this amount to Ofgem to be placed in an escrow account or in the form of a letter of credit (LOC). The costs of putting this LOC in place are included as transaction costs. Where security was provided into an escrow account, the developer will be entitled to the interest that the account has received. Where the security is returned to the developer any interest incurred along with the principle sum will be returned to the developer.

Developer's external and internal costs

2.39. To support their activities in the tender process developers may have had to utilise a range of resources or services including, for example, the production of legal documents or provision of financial advice to support the cost assessment. The use of external and internal resources by developers to support the tender process in this way is consistent with the costs incurred in the development and construction of a set of assets that are being prepared for sale immediately following completion of construction.

2.40. For the purposes of undertaking a cost assessment we have required developers to submit evidence to support the level of external and internal costs that they have submitted. These may be reviewed as part of the forensic accounting investigation.

2.41. 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.

2.42. There may also be internal specialised staff charged directly to the project for undertaking work directly related to the tender process, e.g this could include engineers, accountants, etc. Where this is the case we would similarly require the appropriate evidence of this.

³<http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Offshore%20Electricity%20Transmission%20Tender%20Rules.pdf>

Exchange rates

2.43. We recognise that developers will have adopted different approaches for paying contracts in foreign currency. For example, the developer may have hedged by fixing the forward exchange rate in advance. The payment of their contracts should then be based on such fixed rates. If the developer has not used this approach then the exchange rate must be based on the day rates applicable when payments were made out against the contract in line with the standard accounting application of temporal rates. We have asked developers to outline their approach and provide supporting documentation as necessary. Where developers are unable or unwilling to provide the relevant calculations then we will determine the rate based on the forward rates applicable at the time that the contract approval was made.

Outstanding costs

2.44. When the cost assessment process is completed, cash payments made by the developer may not equal the assessed transfer value 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 (eg greater than 5% of the transmission assets), we have delayed our final assessment until a lower and more accurate figure is available. Where these non-cash items have been considered to be reasonable and do not amount to a significant percentage of the assessed transfer value they are treated as a firm commitment by the developer to allow the assessment to be completed.

Capitalisation of operating costs

2.45. We have decided not to allow the capitalisation of operating costs as this is not within the scope of the cost of developing and constructing the transmission assets. Examples of these costs include set up costs relating to ongoing operational costs (eg maintenance) that may have been capitalised.

3. Barrow cost assessment

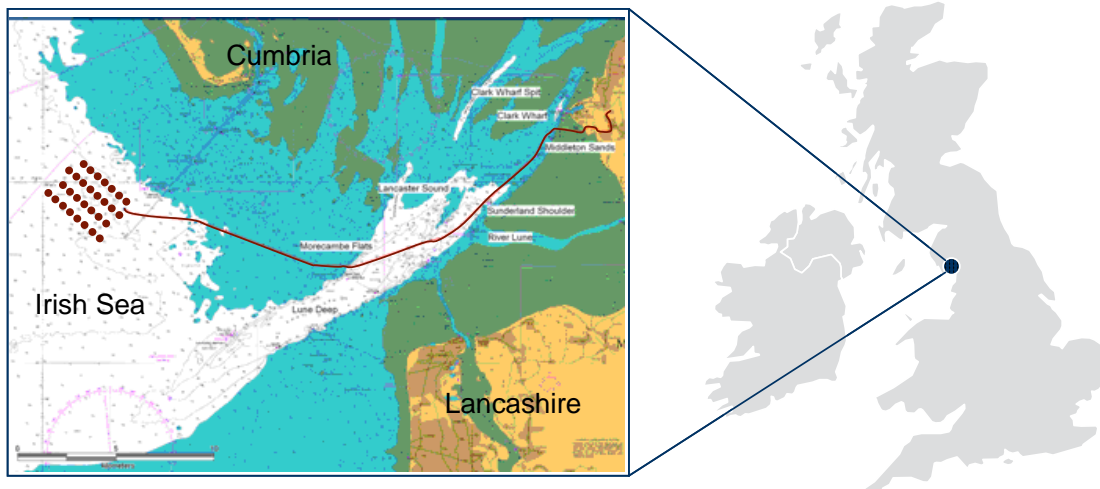
Chapter Summary

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

The Barrow transmission assets

3.1. The Barrow offshore wind farm is located in the East Irish Sea approximately 7km south west of Walney Island (see figure below). The installed capacity of the wind farm is 90MW. The transmission assets were originally developed by Warwick Energy and in September 2003 the rights to develop the project were acquired by DONG Energy, Centrica and Statkraft. Statkraft subsequently sold their share to the other two partners, creating a 50:50 joint venture between DONG Energy and Centrica named Barrow Offshore Wind Ltd (BOW).

Figure 1: Location of the Barrow transmission assets



3.2. The assets that are transferring to the OFTO are the offshore substation, the export cable and the onshore substation with the boundary points defined as:

- Offshore: At the 33kv terminals of the main transformer. The 33kV electrical and control equipment is to be retained by BOW.
- Onshore: At the busbar point above the internal segregation fence in the Barrow/Electricity North West (ENW) substation at Heysham. The boundary is located between the surge arrestors (will be owned by the OFTO) and the metering units (owned by ENW).

3.3. Spares to be transferred to the OFTO are a subsea cable repair kit and a small quantity of onshore cable.

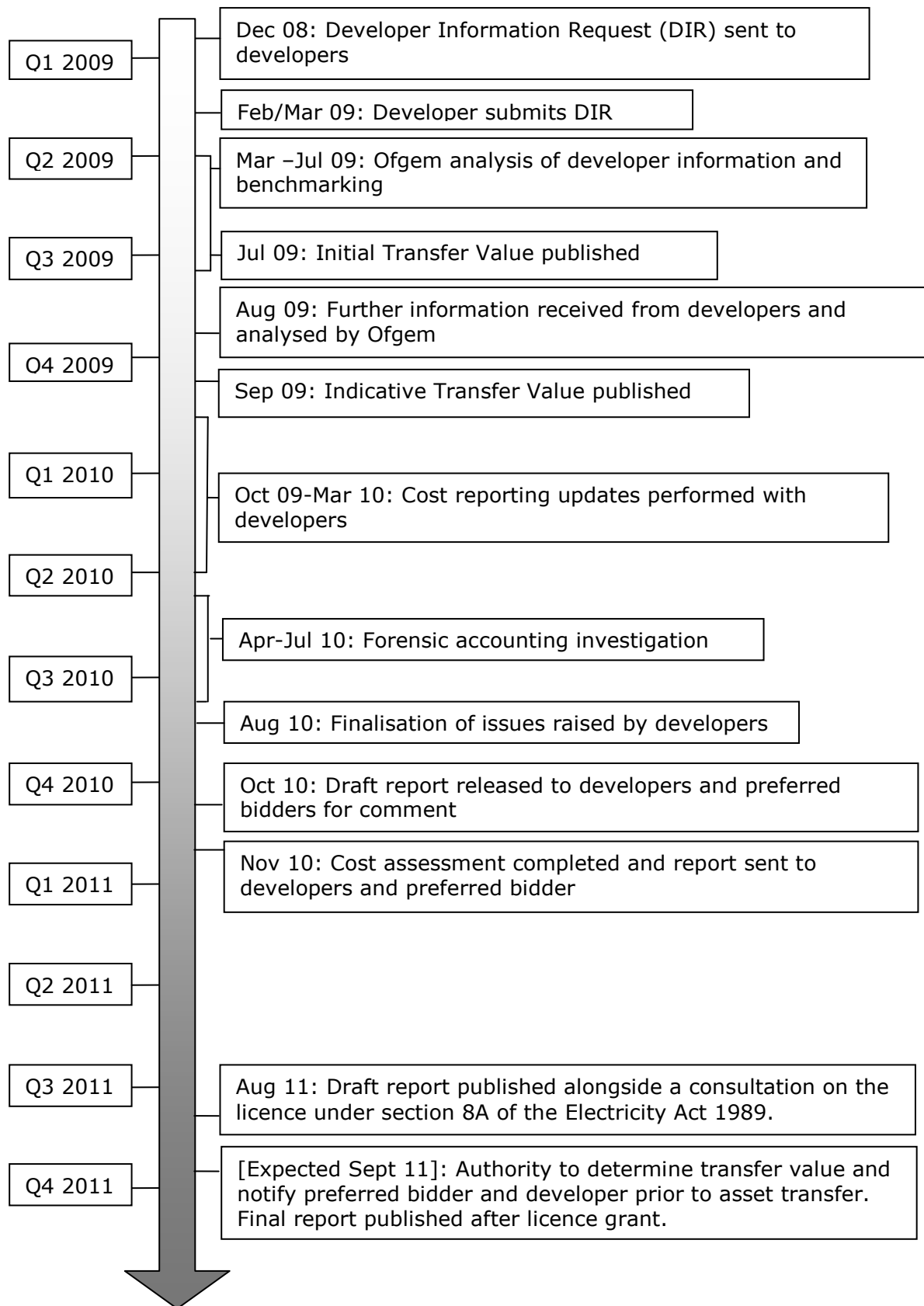


Barrow cost assessment process overview

3.4. Since December 2008, we have worked with the developer and our advisors to reach the assessed costs which will be used by the Authority to determine the transfer value of the transmission assets. The diagram below outlines the steps that have been taken in the cost assessment process for the Barrow project.

DRAFT

Offshore Transmission: Cost Assessment for the Barrow transmission assets



Cost allocation and efficiency

3.5. This chapter details the breakdown of the assessed costs for the capex, development, IDC and transaction cost categories. In Chapter 1 we set out the two tests that were applied to the costs submitted by the developer. These were to assess:

- The accuracy and allocation of the costs
- Whether these costs were incurred economically and efficiently

3.6. The two tests were applied to the developer's costs submissions. In this chapter we identify the cost changes that have resulted from our assessment of the accuracy and allocation of the costs and how we have determined whether costs have been incurred economically and efficiently.

Allocation

3.7. The forensic accounting investigation was undertaken 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 period. We also checked that they were allocated to the correct asset category and had been allocated correctly between generation and transmission. To assess whether the costs have been allocated correctly we have taken into consideration the following:

- Metrics used when allocating costs
- Developer's submissions using our cost reporting template
- A forensic accounting investigation
- Cash flow payments related to the transmission assets

Efficiency

3.8. After costs had been appropriately identified and allocated, we performed an assessment of whether these costs had been incurred economically and efficiently and we took into consideration the following:

- Comparison between the initial and indicative cost submissions leading to the assessed transfer value
- Technical assessment of the project undertaken in 2009
- Benchmarking exercise undertaken in 2009 across all transitional projects to inform the indicative value
- Report on interest during construction

3.9. Barrow is amongst the earliest offshore projects to be assessed. Over time, as further projects are completed, it will be possible to make greater use of actual costs for benchmarking. This will be used in conjunction with the forensic accounting investigation and technical assessments when determining the assessed transfer value.

Cost summary

3.10. The table below provides a breakdown of the evolution for the standard components of the project valuation.

Table 2: Cost breakdown history

Category	Initial Transfer Value July 2009 (£)	Indicative Transfer Value Sept 2009 (£m)	Assessed Transfer Value July 2011 (£)	Reasons for change between Sept 2009 and July 2011
CAPEX	26.3	26.4	25.7	Better identification of costs (reallocation to development) plus a reduction of £0.3m to reflect the impact of contract variations
Development	3.0	3.0	3.5	Increase due to better identification of costs (reallocation from capex) during the forensic accounting investigation
IDC	7.2	7.1	3.0	The developers original IDC submission has been capped at 10.8% and runs to February 2006 only
Transaction	-	-	1.4	Transaction costs not assessable until the end of the cost assessment process
Total	36.5	36.5	33.6	The decrease is largely the result of the cap on IDC in respect of both rate and period of application

3.11. In total the asset transfer value for the Barrow project decreased from £36.5m to £33.6m. As the table shows, whilst the overall value of the project decreased, the value associated with capital expenditure and development was relatively unchanged. This variation is predominantly related to assessment of the appropriate IDC value.

Capital expenditure

3.12. The total capex calculated for the Barrow transmission assets in the assessed transfer value is £25,731,345. As a result of the forensic accounting investigation several changes were made to the developer's submitted numbers to reflect a more

appropriate allocation of cost between generation and transmission. The net change of the results of the allocation test was a reduction of £306,489 to give the figure stated above.

3.13. The developer entered into an EPIC contract with Vestas-KBR in July 2004. This contract covered both generation and transmission and did not allow for differentiation between the two. As a result of this we have reviewed the costs incurred on the entire contract and analysed the information regarding the allocation of costs to the transmission assets presented to us by the developer.

3.14. Vestas-KBR and BOW signed a supplemental agreement in to terminate the EPIC contract. The agreement settled all outstanding variation orders and repayments of claims to BOW due to construction delays. Under the settlement agreement the overall EPIC contract was deemed to be completed on 31 December 2006.

Allocation

3.15. The developer provided documentation regarding the total EPIC contract price and details of how they allocated the costs between generation and transmission. As part of the forensic accounting investigation we analysed the cost allocation to establish whether the proposed split of costs was appropriate.

3.16. From the information provided by the developer and the results of the forensic accounting investigation we made adjustments based on the total EPIC contract cost, variation orders and the allocation methodology. Part of this work identified an alternative breakdown of the asset costs. The adjustments arising from the forensic accounting investigation are outlined below.

Adjustments arising from forensic accounting investigation

3.17. As a result of the forensic accounting investigation two amendments were made against the capex costs that the developers have submitted. These gave rise to a reduction of £360,489 on the following basis:

- BOW's calculation of the proportion of the EPIC contract that relates to the transmission assets was based on the cost of the original contract plus the variation orders. We have calculated an alternative proportion based on the settlement agreement
- A variation order relating to the export cable that was agreed just after the settlement agreement was identified during the forensic accounting investigation. BOW's calculation of the costs did not include this. We have decided to include this cost as it relates directly to the transmission assets

Efficiency

3.18. In the case of the Barrow project, the transmission asset costs are a relatively high proportion of the overall project costs (i.e. from transmission and generation) when compared to other projects in the first transitional round which are operational.

However, we note that Barrow is further offshore and has a lower generation capacity than its comparators. The benchmarking exercise that was undertaken to assist the conclusions on the initial and indicative transfer values did not raise a need for any efficiency adjustments on the capex for Barrow.

3.19. The developers view of the capex costs has not increased in the period between the indicative transfer value and the assessed transfer value, but as a result of the allocation test detailed above we have decreased the total capex. As there was no material increase in expenditure from the indicative transfer value we have decided not to undertake a further investigation.

Post Construction costs

3.20. Reburial works on the subsea cable of the Barrow transmission assets were undertaken subsequent to the assets being commissioned in February 2006. These remedial works were deemed to be necessary by the developer as the cable was buried at an insufficient depth during the initial installation. BOW submitted these costs for inclusion in the cost assessment process.

3.21. After further investigation of these costs we have concluded that they should not be included in the assessed transfer value. The reasons for this are:

- BOW signed a supplemental agreement with Vestas-KBR in February 2007 where the developer agreed to release and discharge the contractor from all existing and future claims (either under warranty or under insurance) resulting from the insufficient burial of the submarine cable;
- As these costs were incurred after the construction had finished and the wind farm became operational, we have decided that these are post-construction costs (i.e. a repair cost or life cycle cost attributable to the then owner which in this case was the generator).

3.22. As a result we have not allowed the developers submitted cost of £1.2m in the assessed transfer value.

Development costs

3.23. The total development costs calculated for the Barrow transmission assets in the assessed transfer value is £3,505,908. These are costs incurred by BOW which were outside the scope of the EPIC contract.

Allocation

3.24. An increase occurred in the development costs from the indicative to the assessed transfer value. The cost change was attributable to better identification of the development costs during the forensic accounting investigation and amounted to an increase in costs of £184,239.

3.25. The indirect costs (including the project purchase costs) have been allocated by the developer to the transmission assets using the same allocation percentage of

the EPIC contract cost attributed by Vestas-KBR (22%). The developers' personnel charges relate to staff who were employed on the project during the construction phase.

3.26. BOW had based their allocation of non-EPIC costs on the proportion of generation to transmission on the original cost rather than the settlement agreement which included variation orders. Based on the revised contract cost the proportion of transmission rises from 22% to 23%.

3.27. The purchase price from Warwick Energy was for the total project and the amount attributed to the transmission assets for Barrow was based on the consistent use of the percentage share of the EPIC contract. This represented 4.0% of overall transmission asset costs. The Barrow project was purchased from Warwick Energy in 2003 by Centrica (25%), DONG Energy (37.5%) and Statkraft (37.5%). In 2004 Statkraft sold its stake in the company to the other partners leaving them joint owners with equal shares. At this time the project was still in the development phase and construction had not commenced.

Efficiency

3.28. The total development costs as a proportion of the overall indicative transfer value was not deemed to be an outlier when compared to other projects and the subsequent cost change identified in the allocation test did not alter this position.

3.29. When the project was purchased, we consider that there would have been a reasonable amount of development work that would have been undertaken by the previous owner, and this would be reflected in the purchase price. To assess if the purchase price was efficient we examined the cash flow of other projects with two and a half years to completion. This indicated that they had all spent in excess of the 5% of total transmission asset costs on development costs by the equivalent stage. We decided that no amendment to the purchase cost level therefore appropriate in this case.

Interest during construction

The total IDC calculated for the Barrow transmission assets in the assessed transfer value is £2,969,424 based on an interest rate of 10.8% and duration of two and a half years from September 2003 to February 2006. The reduction from the initial transfer value is a result of a reduction in the period for the cash flow and the capped interest rate.

Allocation

3.30. The cashflow that the developer provided represented accounting data and not a cashflow with actual payment dates of costs under the EPIC contract. The developer's accounting data finished in February 2006, the date by which the transmission assets were completed. Using the developer's accounting data would have allowed IDC to be calculated on a cost that would not reflect actual funding costs.

3.31. As a result of the forensic accounting investigation it was clear that payments were made after the completion of the transmission assets. It was necessary to use an actual cashflow to ensure that the total duration that IDC was applied was correct. Following analysis of the data provided by the forensic accounting investigation we constructed a cashflow using the EPIC contract payment dates identified in the forensic accounting investigation together with the allocation methodology and included the development costs at a time appropriate to when the cost was incurred in the project construction period.

Efficiency

3.32. The original IDC rate submitted by the developer of the project was above the proposed cap level of 10.8%. Following Ofgem's own analysis and that of our advisors, we concluded that the interest rate should be capped at 10.8% (see paragraph 4.16 in chapter 4). The period during which the IDC was applied was restricted to the date that the transmission assets became operational.

3.33. The Barrow transmission assets were financed and constructed prior to the credit crunch and therefore were not affected by it. However, this project was financed on balance sheet by an integrated European utility. Consequently the appropriate range for interest rates is equivalent to the range that we have determined for the other projects that were financed and constructed during the credit crunch. BOW submitted a post tax interest rate used in the approval for the Barrow project, which we converted to a pre-tax nominal rate. The resultant rate was above the 10.8% cap and therefore not considered as economic and efficient based on analysis we have undertaken. The interest rate of 10.8% on a pre-tax nominal basis for the Barrow project, taken in conjunction with a reduction in the period of financing (which has been limited to the construction period), has resulted in a reduction to £3.0m from the indicative transfer value IDC figure of £7.1m.

Transaction costs

3.34. The indicative transfer value did not contain any transaction costs as they were not known at this time. DONG Energy and Centrica have submitted their view of the transaction costs incurred to date and expected to the year end as a firm estimate to completion. We have assessed the costs submitted and concluded that the transaction costs are £1,350,881.

Allocation

3.35. The developer provided information regarding both internal and external costs. For their internal costs they provided information on the personnel who were involved and their day rate relating to the work undertaken and time spent on the tender process as opposed to the construction of the project or generation activities. The external costs related to professional services in respect of the tender, eg legal, accountancy and technical. We have concluded that the costs provided by the developer were allocated appropriately.

Efficiency

3.36. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. As the tender process for the Barrow project is one of the first to be completed in the first transitional tender round there are a limited number of developers with transaction costs to which we can benchmark the cost. Furthermore, the costs that we do have are not directly comparable due to developers adopting differing approaches to meet the demands of the tender process and the fact that some developers have split their resource across multiple projects in the tender round. We have therefore not applied benchmarking but we have considered the reasonableness of the types and costs of resources incurred in relation to the tender process.

3.37. As more tenders are completed we will have access to a greater pool of transaction costs that developers have incurred and it will be possible to make greater use of actual costs for benchmarking.

Confirmations in relation to tax benefits

3.38. As stated in 4.30 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 assessed 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 assessed transfer value the developer has confirmed that the purchaser will be able to obtain the full benefit of all available capital allowances and therefore it has not been necessary to reduce the assessment of costs.

4. Conclusion

4.1. 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 Barrow transmission assets to be £33,557,558.

Appendices

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Appendix 1 – The Authorities powers and duties

Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority (“the Authority”), the regulator of the gas and electricity industries in Great Britain. This appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below). The Authority's powers and duties are largely provided for in statute (such as the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Acts of 2004, 2008 and 2010) as well as arising from directly effective European Community legislation.

References to the Gas Act and the Electricity Act in this appendix are to Part 1 of those Acts.⁴ Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This appendix must be read accordingly.⁵

The Authority's principal objective is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems. The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.

The Authority is generally required to carry out its functions in the manner it considers is best calculated to further the principal objective, wherever appropriate by promoting effective competition between persons engaged in, or commercial activities connected with;

- the shipping, transportation or supply of gas conveyed through pipes
- the generation, transmission, distribution or supply of electricity
- the provision or use of electricity interconnectors

Before deciding to carry out its functions in a particular manner with a view to promoting competition, the Authority will have to consider the extent to which the interests of consumers would be protected by that manner of carrying out those functions and whether there is any other manner (whether or not it would promote competition) in which the Authority could carry out those functions which would better protect those interests.

In performing these duties, the Authority must have regard to:

⁴ Entitled “Gas Supply” and “Electricity Supply” respectively.

⁵ However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met
- the need to secure that all reasonable demands for electricity are met
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them⁶
- the need to contribute to the achievement of sustainable development.

In performing these duties, the Authority must have regard to the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.⁷

Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed⁸ under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity
- secure a diverse and viable long-term energy supply
- and shall, in carrying out those functions, have regard to the effect on the environment.

In carrying out these functions the Authority must also have regard to:

- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

The Authority may, in carrying out a function under the Gas Act and the Electricity Act, have regard to any interests of consumers in relation to communications services and electronic communications apparatus or to water or sewerage services (within the meaning of the Water Industry Act 1991), which are affected by the carrying out of that function.

The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation⁹ and therefore part of the European Competition Network. The Authority also has concurrent

⁶ Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Acts in the case of Electricity Act functions.

⁷ The Authority may have regard to other descriptions of consumers.

⁸ Or persons authorised by exemptions to carry on any activity.

⁹ Council Regulation (EC) 1/2003.



Cost assessment report for the Barrow transmission assets

powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

Appendix 2 - Glossary

A

Authority

The Gas and Electricity Markets Authority

B

BOW

Barrow Offshore Wind Ltd

C

CAPEX

Capital Expenditure

CBA

Cable Burial Agreement

D

DECC

Department of Energy and Climate Change

DIR

Developer Information Request

E

ENW

Electricity North West

I

IDC

Interest During Construction

IM

Information Memorandum detailing the projects details released to QTT bidders through the tender portal October 2009.

[ITT](#)

Invitation to Tender

M

[MW](#)

MegaWatt

[MVA](#)

MegaVoltAmpere

O

[OFTO](#)

Offshore Transmission Owner

P

[PIM](#)

Preliminary Information Memorandum on the project released at the TR1 PQ stage in July 2009.

[PTRA](#)

Post Tender Revenue Adjustment

Q

[QTT](#)

Qualification to Tender

S

[SCADA](#)

System Control and Data Acquisition

T

[TR1](#)

Transitional Tender Round 1



Cost assessment report for the Barrow transmission assets