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Offshore Transmission: Cost Assessment for the Walney 2 transmission assets

Decision

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Overview:

This document sets out our cost assessment for the Walney 2 transmission assets and the key principles that we have applied in our cost assessment process for the first transitional tender round. The Authority has used the assessment of costs to determine the value of the Walney 2 transmission assets. The Authority has granted an offshore transmission licence to Blue Transmission Walney 2 Limited, which is incorporated by Macquarie Capital Group Limited and Barclays Integrated Infrastructure Fund (managed by Barclays Infrastructure Funds Management Limited).

Blue Transmission Walney 2 Limited 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 referred to in this document.

Context

Ofgem and the Department of 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 regime[1].

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.

This is the sixth cost assessment report for offshore transmission published by Ofgem.

Associated documents

- Ernst and Young report on Interest During Construction Link
- Kema report on benchmarking 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

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

Contents

Executive Summary

This document sets out Ofgem's assessment of the costs which ought to have been incurred in connection with the development and construction of the transmission assets for the Walney 2 project. It also details the cost assessment process we have undertaken.

Key stages of the cost assessment process for Walney 2

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

- The initial calculation of costs for the Walney 2 project was £104.4m. This was communicated to the developer in July 2009 and published in the preliminary information memorandum in July 2009 (the initial transfer value).
- The initial calculation was updated as a result of further information and continuing analysis. The updated calculation, which was £105.0m, was communicated to the developer in September 2009 (the indicative transfer value). The indicative transfer value was published in the project information memorandum.
- At this stage of the cost assessment process we have reached a final decision on the assessment of costs of £109.8m (the assessed transfer value).

The Walney 2 project

Table 1 shows the movement between the initial, indicative and assessed transfer values, and the reasons for movements between the indicative and the assessed transfer value.

Table 1: Summary of cost breakdown history

Category	Initial Transfer Value July 2009 (£m)	Indicative Transfer Value Sept 2009 (£m)	Assessed Transfer value July 2012 (£m)	Reasons for change between Indicative Transfer Value and Assessed Transfer Value
CAPEX	81.6	79.8	93.7	£28.1m increase relates to delays in cable installation, increases in onshore and offshore substation construction costs and hedging losses Offset by (£8.2m) Reduction in the project contingency (£6m) Reduction on disallowed inefficient costs and re-allocation of non-OFTO costs
Development	11.6	10.4	8.3	This reduction is the effect of reallocation of project management costs to CAPEX categories
IDC	11.2	14.8	6.2	Reduction of IDC (£8.6m) due to the following: - the IDC level used being reduced to the capped value, the duration of IDC claimed was shorter and a change in the CAPEX spend profile
Transaction	0.0	0.0	1.6	Transaction costs have been added as they are assessed at the end of the cost assessment process
Total	104.4	105.0	109.8	

CAPEX

Table 1 shows that the assessed transfer value CAPEX is £13.9m greater than the indicative transfer value. An increase of £15.3m was down to a number of factors including weather delays and extra vessel chartering costs. This was compounded by the initial seabed survey not being sufficiently detailed. This meant that unforeseen problems were encountered, causing a knock on increase in costs such as slower installation speeds (to maintain burial depth) and a backhoe vessel for hard soil that was encountered. The CAPEX increase was offset by a reduction in the cable installation costs of (£3.8m) for costs not being economically and efficiently incurred; a reduction of (£1.3m) for SCADA; project management costs due to re-allocations of costs; the removal of a margin in the developers man-hour rate; a reduction on the allowed project management costs for the onshore substation; and, the elimination of the project contingency.

Development costs

Table 1 shows that over the duration of the project, development costs have changed due to a reallocation of project management costs to CAPEX cost categories.

Interest during construction (IDC)

The IDC allowance has decreased from the indicative transfer value to the assessed transfer value. This is a result of: a reduction in the applicable rate for IDC; the period of IDC entitlement ending in August 2011 as against the previous estimate of it running until December 2011; and, the actual CAPEX profile being back loaded (as against the original projection of an even profile). The amount of IDC also included a reduction for the costs that we have not included in the assessed transfer value.

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 in relation to this issue.

Assessed transfer value for Walney 2

The assessed transfer value of the Walney 2 transmission assets is £109,758,628.

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 that we 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 (CAPEX)
- 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 Transitional Round 1

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.

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 to ensure 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 costs 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 six projects within Transitional Round 1 (TR1) (Barrow, Robin Rigg, Walney 1, Gunfleet Sands, Ormonde and Walney 2). 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 (IDC)

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. Our advisors 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 had 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 transitional round 1 projects.

2.21. We published a consultation and conclusion on IDC in August 2011 which sets our approach to IDC. We will review our approach to IDC (the rate, the cap and the date) from time to time and our approach to its 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[2]. The commercial supply of electricity to the transmission system which follows commissioning also indicates that the assets are complete and operational.

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[2] In this context, we would view commissioning as hot commissioning which enables energisation of the transmission system.

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[3]. 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.

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 cash flows. This has not been used by us 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

[3] For the avoidance of doubt, this should not be confused with legal definition of transmission for transitional projects. The system becomes transmission only when transferred to an OFTO. However, we would not apply IDC to this point.

been identified during the forensic accounting investigation we have sought the correct 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 value does 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. As a result, contingency is 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. Her Majesty's Revenue and Customs (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 methodology[4] in relation to the Authority's costs in this respect.

4http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Offshore%20Electricity%20Transmission%20Tender%20Rules.pdf

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. We do not allow any profit margin on internal staff costs to be included in the cost assessment.

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

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. Walney 2 cost assessment

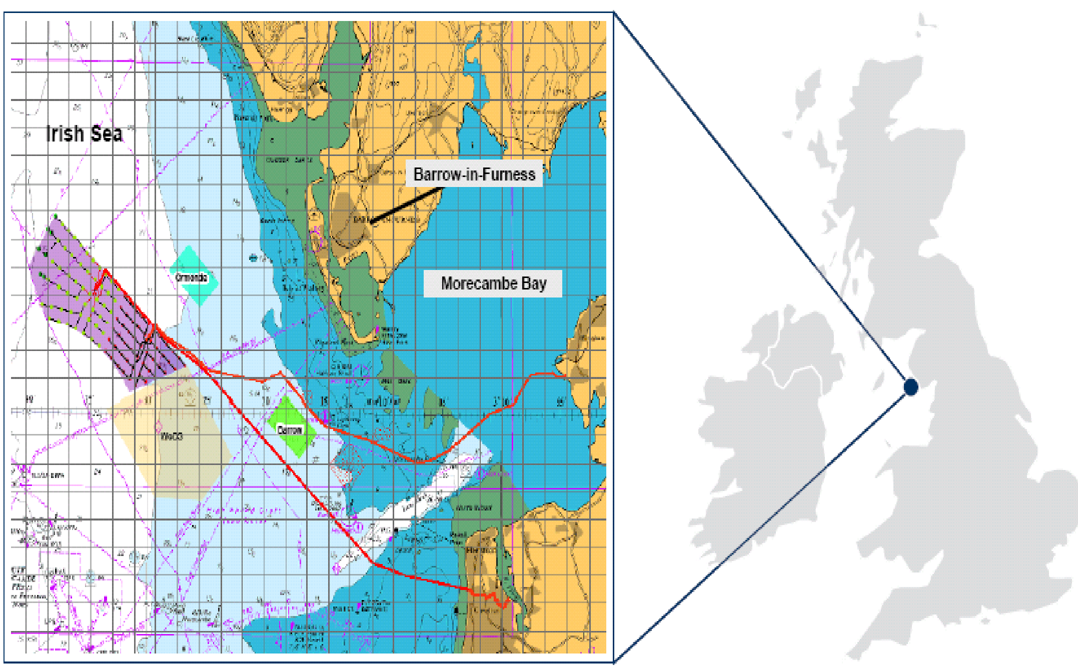
Chapter Summary

This chapter summarises how we have developed our cost assessment for the Walney 2 transmission assets from the initial transfer value to the assessed transfer value, with an emphasis on the difference between the indicative and assessed transfer value. It provides a breakdown of the key cost categories that we have considered and highlights the decisions that we have made.

Walney 2 transmission assets

3.1. The Walney 2 Wind Farm is located approximately 15km west of Walney Island and some 18km from Barrow-in-Furness, off the Cumbrian coast in northwest England. The Walney 2 transmission assets were commissioned in August 2011. The Walney 2 Wind Farm consists of 51 3.6MW wind turbine generators (see Figure 1).

Figure 1: Location of the Walney 1 and Walney 2 transmission assets



3.2. The developer of the Walney 2 transmission assets and Walney wind farms (1 and 2) is Walney (UK) Offshore Windfarms Ltd, a joint venture between DONG Wind (UK) Limited (50.1%), SSE (25.1%), and OPW[5] (24.8%), with DONG Energy as the leading partner in the construction and operational phases of the Walney offshore wind farms.

3.3. The assets that are transferring to the OFTO are the export cables, the offshore substation (minus the 33kV switchgear), the onshore substation and an onshore cable linking the subsea connection to the onshore substation. The boundary points are defined below:

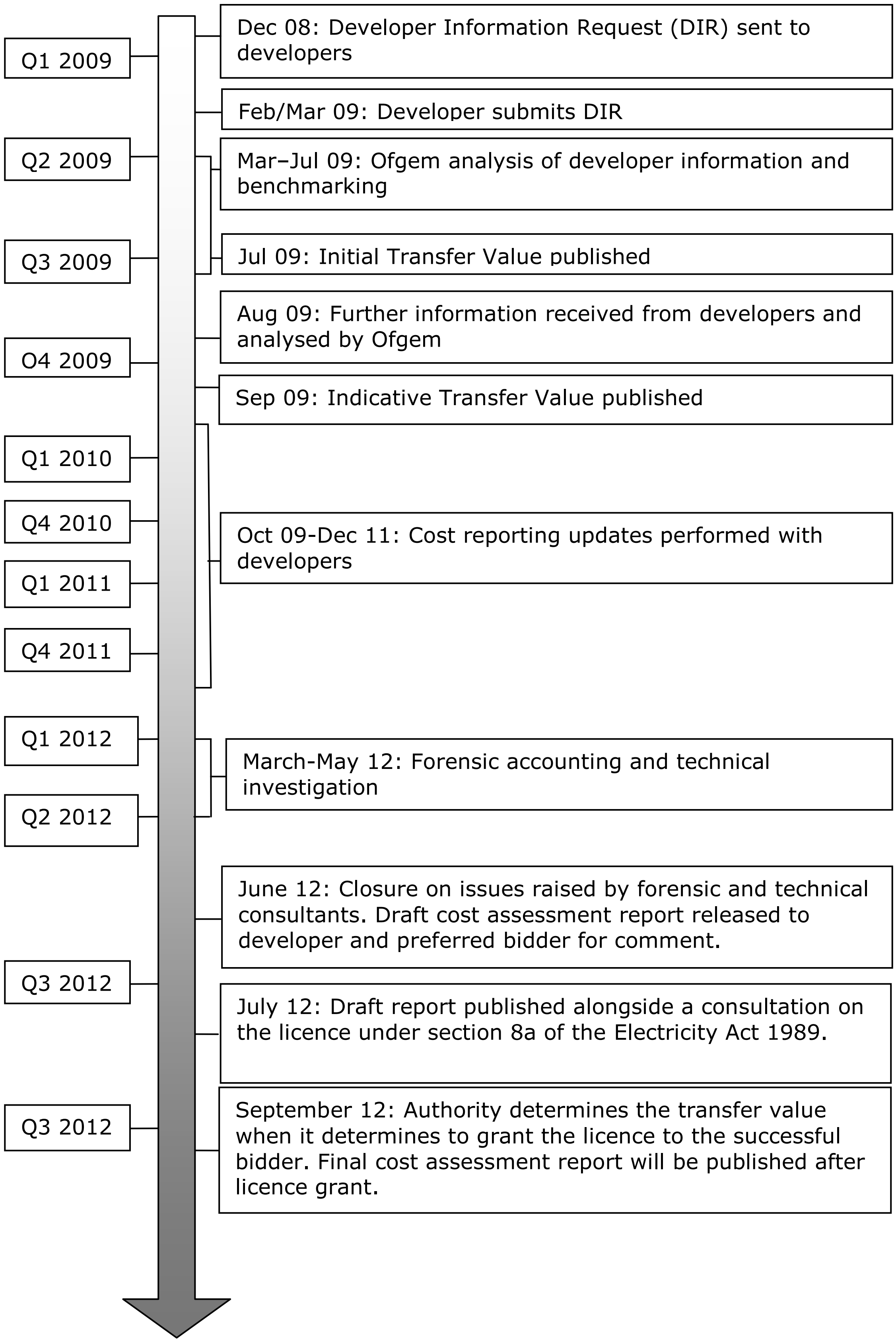
- Offshore: Located on the offshore substation at the transformer cable sealing end of the 33kV cables connected to the 132/33kV transformer
- Onshore: Located within the onshore substation at Electricity North West (ENW) 132kV busbars, with the busbars in the line bay itself being the interface between ENW and the Walney 2 transmission assets

3.4. Spares that will be transferred to the OFTO are 600m of offshore cable, 655m of onshore cable, two submarine cable joints and six onshore joints.

Walney 2 cost assessment process overview

3.5. Since December 2008, we have worked with the developer and our advisers 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 Walney 2 project.

[5] OPW is a company jointly owned by Dutch pension administrator PGGM and Ampère Equity Fund.


Q1 2009
Q2 2009
Q3 2009
O4 2009
Q1 2010
Q4 2010
Q1 2011
Q4 2011
Q1 2012
Q2 2012
Q3 2012
Q3 2012
Dec 08: Developer Information Request (DIR) sent to developers
Feb/Mar 09: Developer submits DIR
Mar–Jul 09: Ofgem analysis of developer information and benchmarking
Jul 09: Initial Transfer Value published
Aug 09: Further information received from developers and analysed by Ofgem
Sep 09: Indicative Transfer Value published
Oct 09-Dec 11: Cost reporting updates performed with developers
March-May 12: Forensic accounting and technical investigation
June 12: Closure on issues raised by forensic and technical consultants. Draft cost assessment report released to developer and preferred bidder for comment.
July 12: Draft report published alongside a consultation on the licence under section 8a of the Electricity Act 1989.
September 12: Authority determines the transfer value when it determines to grant the licence to the successful bidder. Final cost assessment report will be published after licence grant.

Ex-Ante determination summary

3.6. The initial transfer value in July 2009 was £104.4m. This was an estimated value, 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 stage and these were considered in greater detail when the indicative transfer value was set.

3.7. We established an indicative transfer value (ITV) of £105.0m in September 2009. This was based on the costs submitted by the developer of £106.7m, of which £1.7m was not included because the developer had used a greater IDC rate to that which we considered acceptable at that time.

Process for determining the assessed transfer value

3.8. 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; and
- whether these costs were incurred economically and efficiently.

3.9. These two tests were applied to the developer's CAPEX, development, IDC and transaction 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.

Accuracy and Allocation

3.10. The Walney 2 project was constructed on a multi contract basis. An ex-post forensic accounting investigation was undertaken by our advisor Ernst and Young (E&Y) 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. This investigation covered the four main contracts within the transmission assets, which in this case covered the cable supply, installation, the onshore and offshore substation contracts. We also checked that they were allocated to the correct asset category and that they 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
- the findings of the forensic accounting investigation
- cash flow payments related to the transmission assets.

Efficiency

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

- a technical assessment of the project undertaken in 2009
- a benchmarking exercise undertaken in 2009 across all transitional projects to inform the indicative value and which was updated in early 2011
- a report on interest during construction
- the findings of the forensic accounting investigation.

3.12. Walney 2 is a transitional tender round 1 offshore project and is the 6th project to be assessed. 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 investigation and technical assessments when determining the assessed transfer value.

3.13. Although cost benchmarking against the previous five completed projects was not used, due the similar nature and size of the project, Walney 1 was used as a relevant comparator for project management costs and the overall project delivery costs.

Project specific issues

3.14. The Walney 2 project experienced construction issues that have led to increased costs being incurred on the project, mainly in relation to the cable delivery and installation process. In determining the assessed costs for the project we have discussed in detail with the developer:

- the causes of additional costs being incurred in connection with the cable delivery and installation process;
- the decisions and actions that were taken by the developer in light of the cable related issues;
- the contractual framework that underpinned the developer's procurement of services; and
- the project development activities related to the cable installation process.

3.15. Set out below is a summary of these project specific issues:

- In 2009, the developer contracted Visser and Smit (V&S) to install the subsea cable (for both the Walney 1 and Walney 2 projects). The V&S contract provided for a tightly defined cable installation timeframe and the cable was to be laid by May 2011. However, the V&S vessel was contracted elsewhere after this date and the contract made minimal provision to deal with circumstances where the cable laying was delayed past this date. Just prior to the end of 2010, the developer was informed by the cable manufacturer (Prysmian) that the subsea cable would be delivered late. As a result, V&S would no longer be able to lay the entire cable by May 2011. In order to mitigate this potential delay, the developer obtained offers from a number of other cable installation contractors and subsequently engaged Prysmian. This resulted in the subsea export cable being delivered in two sections, with V&S laying the first 2/3 of the overall length, starting from the near shore, and Prysmian laying and jointing the remaining 1/3 section, starting from the offshore substation. This incurred considerable additional costs.

- The weather conditions during the cable laying period were far worse than would have been expected from meteorological results in previous years for that time of year. This led to variation orders (VOs) being raised by the contractors for weather delays during cable laying.

- The soil conditions were harder than suggested in the preliminary seabed surveys that were provided to V&S by the developer. Subsequent survey data provided by the developer did not contain soil strength observations. The near shore landing point required a specialist vessel to assist in laying that stretch of cable. Another section being laid by V&S required the laying speed to be reduced below the contractual agreed rate in order to achieve a satisfactory depth of laying; this entitled V&S to raise a VO. Further, due to the delays in laying speed and weather, V&S were required to surface lay the last 9km of the portion of cable for which it was responsible, in order to meet up with the Prysmian vessel and stay within V&S's contractual period. The surface laying required a further contractor to be subsequently engaged to water jet the cable route and trench this section.

- There was an increase in project management costs since the initial transfer value, in particular in relation to the onshore and offshore substations and the inclusion of a margin on hourly rates from 2012.

3.16. These issues are discussed further in the section on assessment of CAPEX.

Cost summary

3.17. Following completion of construction and development of the transmission assets, the developer submitted costs which would amount to a proposed transfer value of £116.7m. 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 an assessed transfer value of £109.8m. Table 2 below provides a breakdown of the changes in cost for the main components of the project at each of the valuation stages, and an overview of the CAPEX cost movements between the initial, indicative and assessed transfer value.

Table 2: Cost breakdown history

Category	Initial Transfer Value July 2009 (£m)	Indicative Transfer Value Sept 2009 (£m)	Assessed Transfer value July 2012 (£m)	Reasons for change between Indicative Transfer Value and Assessed Transfer Value
CAPEX	81.6	79.8	93.7	£28.1m increase relates to delays in cable installation, increases in onshore and offshore substation construction costs and hedging losses Offset by (£8.2m) Reduction in the project contingency (£6m) Reduction on disallowed inefficient costs and re-allocation of non-OFTO costs
Development	11.6	10.4	8.3	This reduction is the effect of reallocation of project management costs to CAPEX categories
IDC	11.2	14.8	6.2	Reduction of IDC (£8.6m) due to the following: - the IDC level used being reduced to the capped value, the duration of IDC claimed was shorter and a change in the CAPEX spend profile
Transaction	0.0	0.0	1.6	Transaction costs have been added as they are assessed at the end of the cost assessment process
Total	104.4	105.0	109.8	

3.18. The increase from an initial transfer value of £105.0m to an assessed transfer value of £109.8m is mainly due to movements in CAPEX costs. The issues we have considered in setting the assessed transfer value are detailed below.

Overview of CAPEX

3.19. The CAPEX element of the assessed transfer value is £93.7m, which is £13.9m higher than the CAPEX element of the indicative transfer value.

3.20. Our advisors undertook an ex-post forensic investigation of the four highest value CAPEX contracts. These accounted for the majority of the total CAPEX costs submitted by the developer at the time the investigation was undertaken. In total this sample represents 58% of the assessed transfer value (excluding IDC and transaction costs). The CAPEX contracts that we investigated were:

- Visser & Smit (installation of subsea cable)
- Prysmian (supply of subsea cable and subsequent cable laying VOs)
- BBUS (installation of onshore cable)
- Bladt (installation of the offshore substation).

Accuracy and allocation of CAPEX costs

3.21. For the majority of CAPEX costs incurred on the project, it was relatively clear whether they should be allocated to the transmission or the generation assets in their entirety. Where costs have been split between generation and transmission, the developer has allocated the percentage to the transmission assets using cost drivers, which differ depending on the nature of the work undertaken. Only those costs related to the transmission assets were allowed for the initial, indicative and assessed transfer values.

3.22. CAPEX costs that were referenced to documentation that is clearly applicable to the transmission assets have been allocated by the developer to the transmission assets on an actual basis, for example, foundation and insurance costs.

3.23. The developer has allocated 7% of the supply and installation costs in respect of the foundations for the wind turbine generators and offshore substation to the transmission assets. The allocation is based on the number of offshore foundations as a proportion of total number of foundations. We agree this is an appropriate allocation method.

3.24. As summarised in paragraph 3.15, the project experienced delays in the manufacture of the subsea export cable by Prysmian, the cable manufacturer. This resulted in the developer putting in place a revised delivery and installation strategy, whereby the cable was delivered and installed in two parts. The developer took delivery of two thirds of the cable initially, as an estimate of the amount which could feasibly be installed by V&S by May 2011 (which was the date by which V&S were to install the cable under the cable installation contract). Prysmian was subsequently contracted to lay and joint the remaining one third segment of cable. The developer made a claim for liquidated damages (LDs) under the Prysmian cable supply contract for the impact of the delayed cable delivery. The LDs have been netted off against the Prysmian cable installation contract for the purpose of the assessed transfer value. We believe that this is an appropriate method for dealing with this allocation of the LDs.

3.25. V&S and Prysmian raised a number of VOs which increased cable installation costs[6]. We have reviewed the rationale for these allocations and consider the costs have been appropriately allocated.

3.26. The developer had initially allocated the £596k total cost of all of the Supervisory Control And Data Acquisition (SCADA) equipment to the transmission assets as this was still under negotiation with the OFTO. The developer subsequently re-submitted the allocation for the SCADA equipment once agreement had been reached with the OFTO, reducing the allocation to the transmission assets to £348k.

3.27. In the E&Y forensic investigation, it was noted that the man-hour rate used by the developer post 1 January 2012 was adjusted. This adjustment was removed for the purpose of the assessed transfer value.

3.28. We queried the amount of time allocated to work on the offshore substation. The developer subsequently confirmed that £0.8m of its submission should be reallocated to the generation assets.

3.29. After the ITV submission in September 2009, the developer noted that it had incorrectly included an operate and maintain cost of £0.9m. This amount was subsequently removed from the CAPEX costs.

Efficiency of CAPEX costs

3.30. We have reviewed the additional CAPEX costs submitted by the developer, and considered the advice of our technical advisors. We have decided not to include £3.8m of these costs in the assessed transfer value, on the basis that these costs were not in line with our views on the economic and efficient level of costs that ought to have been incurred (as detailed further below).

Export cable supply and installation

3.31. The project incurred additional costs arising from the late delivery of the export cable. We undertook a technical investigation to understand the problems that were encountered and whether the additional costs proposed by the developer were economic and efficient. The following sections expand on the nature of the V&S variation orders (VOs) and the additional contract with Prysmian; the findings of our technical investigation; and, our view on the efficiency of the costs incurred.

Chronology of events leading to extra costs

3.32. The developer was informed prior to the end of 2010 that the cable being manufactured by Prysmian was going to be delivered late. As a result, V&S would no

[6] Increased costs were as a result of vessel waiting on weather, vessel standby and additional cable burial charges for hard soil conditions.

longer be able to install the cable in the agreed contractual timeframe. The developer recognised that the late delivery of the cable would impact on the project's construction timelines.

3.33. To minimise construction delays the developer chose to take delivery of the cable in two sections. V&S laid the cable for 2/3 of the route, using the Stemat Spirit vessel. After receiving quotes from 3 contractors for laying cable along the remaining 1/3 of the route, Prysmian were chosen, as; they were nominally the cheapest[7]; they were willing to absorb the further delivery delay risk for the remaining length of cable; and, they were able to perform the jointing of the two lengths of cable.

3.34. The V&S vessel started laying cable at the near shore, and the Prysmian vessel started laying at the offshore substation. The vessels were scheduled to meet at the two-thirds point along the route from shore, where Prysmian would joint the cable lengths.

3.35. The vessels involved in the cable installation process encountered worse weather than expected during the cable laying operations. This resulted in delays and all contractors submitting VOs for weather related costs.

3.36. V&S encountered hard soil conditions both at the near shore and towards the end of their laying length. The first of these required the hiring of a V&S backhoe trencher to assist in laying the near shore length of cable; the latter required V&S to slow down its laying speed, in order to achieve the required depth of cable lay. Both of these resulted in V&S raising VOs and additional costs.

3.37. As a result of bad weather and hard soil conditions, delays were encountered by the Stemat Spirit vessel, such that it ran out of time to bury the 2/3 length of cable. In order to meet its further contractual commitments and ensure a rendezvous with the Prysmian vessel (to enable the joint to be made), the last 9km of this cable length was surface laid. This surface laying required an additional contractor to water jet a trench and bury the cable, at a further cost.

Conclusion of Kema technical investigation

3.38. In reviewing the sequence of events and resulting costs, the Kema technical investigation highlighted that V&S had not been provided with a detailed initial seabed survey by the developer, and so it was not adequately prepared for the soil conditions encountered during the laying process. Further, the contract with V&S was inflexible, such that any delay to the timetable would result in additional costs. These factors combined to contribute a significant amount of additional cost to the cable laying process. In Kema's view, a more robust seabed survey would have

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[7] The quoted price from Prysmian had netted off the liquidated damages the developer was entitled to; the contract required the developer to waive its rights to claim any liquidated damages.

allowed V&S's contract to be more appropriate for the task, and may have led to a more efficient outcome.

Ofgem's view on efficiency of costs incurred

3.39. We note the developer's approach to handling the issues that arose during the cable procurement and burial process. It reacted to managing the situation once it was informed of the late delivery of the cable, by: reallocating the V&S resource to maximise its use in the available time period; coming to an agreement with Prysmian by which Prysmian took on an amount of contingent risk; and, slowing up the cable laying speed when soil conditions were harder than expected, rather than laying it to an insufficient depth, which would have required further (and likely more costly) remedial action later on. The developer correctly pointed out that the late delivery of the cable was not their fault and was most likely something that they could not have prevented.

3.40. The developer did not undertake a detailed soil survey on the basis that, it considered the initial survey to be sufficient for the purposes of tendering for the cable installation contract. The developer suggests that even if they had known of the hard soil conditions in advance, it would not have saved any of the costs they incurred during the laying process. The developer proposed that all of the additional cable installation costs should be included in the assessed transfer value on this basis. We acknowledge that, once the developer was informed of the late cable delivery, it managed the unfolding events in a reasonable manner, so that the overall project timeline was not compromised. However, the cost assessment process includes consideration of what costs ought to have been incurred in the construction and development of the assets. It is on this basis that we have not allowed all of the additional cable installation costs to be included in the assessed transfer value. These matters are discussed in detail below.

3.41. The initial contracts with V&S to lay the cable (for both the Walney 1 and Walney 2 projects) were agreed in 2009. The contracts were inflexible, both in terms of dealing with delay and the scope for variation in response to changing needs. There was no contingency plan for changes in circumstances (such as delays to elements within the project delivery) other than to incur additional costs. Furthermore, the developer did not provide in a timely manner detailed soil surveys to V&S, which they were supposed to do under the V&S contract. As a consequence, V&S were not made aware of the nature of the soil conditions prior to the cable laying operation.

3.42. We consider that had V&S been provided with a detailed survey prior to the cable laying operation, and had a sufficiently flexible contract been in place that included mechanisms to enable project difficulties to be managed efficiently, a better overall cost of cable installation could have been obtained. By having a more detailed survey prior to laying the cable, V&S would not have been slowed down so much through the laying operation. This could have avoided some of the additional costs from slowing down the laying rate and having to employ an additional contractor to water jet and finish the cable laying process. Having greater flexibility on the start dates and duration of the laying process, along with better contractual mitigation controls in place, could have avoided some of the extra cost involved in contracting an additional laying vessel.

3.43. By entering into the contract arrangements with V&S the developer has accepted an element of risk associated with the cable laying activities involved. The developer has also recognised that insufficient information was presented to V&S on the underlying soil conditions; this created a further risk for the developer to the cable installation process. We consider that project risks should sit with those best placed to manage them; in this case, the risk of delay and an appropriate amount of the associated costs should sit with the developer. DONG have commented that if we expect developers to assume the full cost of the risks itemised above, then it will result in more expensive contracts with their service providers as they pass these risks down the contract chain; this will ultimately result in greater cost for consumers. We agree that in some circumstances, flexibility in contracting will result in extra upfront costs. However, there are instances where it is prudent to build in such flexibility, as the consequences of things going wrong can be comparatively significant. Cable laying has consistently been a source of large cost overruns on offshore transmission projects; we consider that this developer's considerable experience in this area should have resulted in it being more alert to the potential consequences and therefore ensured that reasonable mechanisms were put in place through its contractual and commercial arrangements to enable such consequences to be managed efficiently.

3.44. We have outlined above how greater contractual flexibility and planning could have avoided some of the costs incurred. To include all of the additional costs arising from the late delivery of the cable in the assessed transfer value would pass a considerable amount of project risk in this area back to the consumer. This is unacceptable, as the developer should take some level of the risk and this is reflected in the level of IDC used.

3.45. We consider that in this specific instance, the economic and efficient costs which ought to have been incurred in connection with delivery and installation of the subsea cable amount to 70% of three specific CAPEX VOs and an additional contracts in the Assessed Transfer Value. The increased proportion (ie 70% as against the 50% for Walney 1) of inclusion relative to that for the final transfer value in the case of Walney 1 is as a consequence of the more pro-active stance on issue management adopted for this project.

Additional survey costs

3.46. We understand that an independent post cable installation survey was undertaken by the developer. A number of transitional tender round one projects have experienced cable installation problems which have resulted in increased construction costs. We recognise that the laying and burying of subsea cables is a complex activity which can create a number of technical challenges. A key issue for an incoming offshore licensee is understanding whether the cable has been buried appropriately as this will indicate the extent of additional remedial work that is required before and post transfer. In this case we acknowledge the rationale and need for an additional survey, given the cable installation issues described above, and therefore we have included the full associated costs of £1.1m in the assessed transfer value.

Development costs

3.47. The total development cost calculated for the Walney 2 transmission assets in the assessed transfer value is £8.3m. These are costs incurred by the developer which were outside the scope of the main construction contracts. For the purposes of informing our cost assessment our advisors investigated the project's development costs.

Accuracy and allocation of development costs

3.48. The development costs for Walney 2 cover a variety of items relating to consultancy, engineering, legal costs, etc. The majority of items were common to both transmission and generation and have been allocated accordingly by the developer. We have analysed the developer's allocations individually and as an overall aggregate to ensure that they are appropriate.

3.49. The developer has allocated 16% of insurance costs to the transmission assets using a calculation based on the proportion of the total costs of the transmission assets in comparison to the total estimated costs of both the transmission assets and the Walney 2 wind farm assets8. We consider that this is an appropriate means for allocating the insurance costs.

3.50. An allocation of 25% of transport costs incurred between the start of construction and August 2011 and 1% of transport costs incurred between September 2011 and January 2012 was made to the transmission assets by the developer. This allocation is based on management estimate. We understand that the majority of transport costs relate to transporting employees between the Cumbrian coast and the Walney 2 wind farm assets. We consider that this is an appropriate allocation method.

3.51. The Developer has allocated 25% of site costs to the Walney 2 transmission assets based on a management estimate. We understand that site costs relate to costs such as legal, travel and consents costs. We have reviewed the rationale for this allocation and consider that the costs have been appropriately allocated.

3.52. Project management has been undertaken by the developer and the costs and activities have been reviewed by our advisors. The allocation to the transmission assets has been based on timesheet data and expenses records that were maintained by the developer. Project management costs have been allocated to the transmission assets using a proportion of 29.2% of the total project management costs incurred by the developer in respect of the entire Walney 2 project. This was based on a review of all developer staff costs charged to the Walney 2 project conducted by the developer in January 2012. We requested more detail on the project management costs for the onshore and offshore substations and this

[8] 16% is calculated as the total value of direct and indirect costs relating to the Walney 2 transmission assets as a percentage of the total cost of the Walney 2 transmission assets and Walney 2 wind farm assets.

subsequently lead to a reallocation of project management costs (£0.8m) being re-allocated to the generation assets. Of the remaining allocations, we consider the costs have been appropriately allocated.

Efficiency of development costs

3.53. The project management cost associated with the onshore and offshore substations for this project have been compared to the equivalent costs for the Walney 1 project. The project management costs for Walney 2 are higher than for Walney 1.

3.54. We have raised this matter with the developer and it has not provided sufficient justification to explain the differences. For this reason we have decided not to include the project management cost for the onshore substation (£56k).

3.55. It has been noted that the man-hour rate that the developer has applied to the project from January 2012 contains a margin. A margin is not allowed to be made on any items related to the transmission assets, consequently we are not including the mark up in the man-hour rate used by the developer. This represents £81k of costs disallowed from the developers submitted transfer value. The £81k value was removed from the CAPEX in the asset categories that include the margin on the post 1 January 2012 hour rates. The land cable didn't have any reduction as there was no developer costs associated with this asset post 2012.

Interest during construction

3.56. The total IDC calculated for the Walney 2 transmission assets in the assessed transfer value is £6.2m, based on the developer's calculation of the interest rate to completion of the assets over a period from August 2006 to end August 2011. The main changes from the indicative transfer value are a result of the IDC rate being capped; the developer's actual cash flow being very different from the accounting data originally submitted and reductions in the period of the cash flow.

Accuracy and allocation of IDC

3.57. The cash flow that the developer provided for the indicative transfer value represented accounting data and not a cash flow with actual payment dates of costs under the contracts. The period of application of IDC was forecast to end in December 2011. For the assessed transfer value the developer provided an actual cash flow with the IDC ceasing in August 2011.

3.58. For the purposes of IDC, we consider that construction ceases once the transmission assets are commissioned[9]. The commercial supply of electricity to the transmission system which follows commissioning also indicates that the assets are complete and

[9] In this context, we would view commissioning as hot commissioning which enables energisation of the transmission system.

operational. Entitlement to IDC ceases when the assets are ready to transmit and so we have stopped the project's IDC from August 2011. This is in line with the Interim Operational Notice date from National Grid of the 23 August 2011 and subsequently we have disallowed £1.9m from the assessed transfer value to reflect this.

3.59. The CAPEX costs that we have disallowed have been removed from the cash flow at a period which is relevant to when the work was invoiced or undertaken.

Efficiency of IDC

3.60. The original IDC rate submitted by the developer for the indicative transfer value was above the cap level to be applied during construction. The developer's final transfer value submission reflects the reduction that this capped value has on the final IDC value.

3.61. As noted before, the cash flow that the developer provided for the indicative transfer value represented accounting data and not the actual cash flow. The actual cashflow was submitted with IDC being claimed to October 2011, not the forecast December 2011 in the initial transfer value, reducing the IDC claimed. The actual cashflow profile was also back-end loaded toward the end of the project, causing a further reduction in the IDC being claimed.

Transaction costs

3.62. The indicative transfer value did not contain any transaction costs as they were not known at the time. The developer has submitted their view of the transaction costs incurred to date and a firm estimate of the costs they expect to incur to asset transfer. The total of these items results in the transaction costs element of the assessed value being £1.6m.

Accuracy and allocation of transaction costs

3.63. 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 of transaction costs

3.64. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. The transaction costs submitted by the developer represent less than 2% of the total CAPEX and development costs. Table 3 below sets out a comparison of transaction costs for Walney 2 compared to other projects:

Table 3: Transaction costs submitted/included in the assessed transfer value

Project	Assessed transfer value £m	Transaction costs £m	Transaction costs as % of transfer value
Robin Rigg	65.5	0.7	1.1%
Gunfleet Sands	49.5	1.3	2.6%
Barrow	33.6	1.4	4.2%
Walney 1	105.4	1.7	1.6%
Ormonde	103.9	1.0	1.0%
Walney 2	109.8	1.6	1.5%
Average			2.0%

3.65. The Walney 2 project is the 6th project to be assessed in the first transitional tender round there are a limited number of developers with transaction costs to which we can benchmark transaction costs. Furthermore, the costs that we do have are not directly comparable to other projects 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 of resource costs incurred in relation to the tender process. For this project, we do not have any evidence that the proposed transaction costs are at an inappropriate level.

3.66. 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. We have otherwise relied on ensuring costs are accurate in order to ensure the associated transfer value is appropriate for the Walney 2 transmission assets.

Hedging

3.67. Companies who pay for contracts in a different currency from their home currency will often employ a hedging strategy to protect them against exchange rate fluctuations, usually done via their central Treasury function. This hedging gain or loss only becomes explicit on the project overview because the relevant accounting system calculates transactions on the day rate. A hedging correction factor must then be introduced to bring the project accounts back into line with the hedge and the actual cost incurred. We treated the hedging gain or loss as an economic and efficient cost on the basis that it is prudent practice for companies to hedge foreign currency risk in this way given their income is in sterling. This is consistent with the approach taken on other projects in the first transitional round.

Contingency

3.68. The assessed transfer value did not contain a separate contingency value. The developer has identified a small number of cost estimates for future payments in relation to the transmission assets for inclusion in the assessed transfer value.

Confirmations in relation to tax benefits

3.69. As stated in 2.31 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 Walney 2 transmission assets to be £109,758,628.

Appendices

Index

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.[10] 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.[11]

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:

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[10] Entitled "Gas Supply" and "Electricity Supply" respectively.
[11] 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 them[12]
- 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.[13]

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 licensed[14] 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 Regulation[15] and therefore part of the European Competition Network. The Authority also has

[12] 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.
[13] The Authority may have regard to other descriptions of consumers.
[14] Or persons authorised by exemptions to carry on any activity.
[15] Council Regulation (EC) 1/2003.

concurrent 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

C

CAPEX

Capital Expenditure

D

DECC

Department of Energy and Climate Change

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.

PQ

Pre-qualification

PTRA

Post Tender Revenue Adjustment

Q

QTT

Qualification to Tender

S

SCADA

System Control And Data Acquisition

T

TOGC

Transfer of Going Concern

TR1

Transitional Tender Round 1