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Offshore Transmission: Cost Assessment for the Sheringham Shoal transmission assets

Decision

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Overview:

This document sets out our cost assessment for the Sheringham Shoal 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 Sheringham Shoal transmission assets. The Authority has granted an offshore transmission licence to Blue Transmission Sheringham Shoal Limited, which is incorporated by Macquarie Capital Group Limited and Barclays Integrated Infrastructure Fund (managed by Barclays Infrastructure Funds Management Limited).

Blue Transmission Sheringham Shoal 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 run for the grant of offshore electricity transmission licences in the first transitional tender round. 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 seventh cost assessment report for offshore transmission published by Ofgem.

Associated documents

- Kema report on benchmarking Link
- Ernst and Young report on Interest During Construction 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
- Offshore Transmission: Guidance for Cost Assessment 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 Sheringham Shoal offshore transmission project. It also details the cost assessment process we have undertaken.

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

- The initial calculation of costs was £186.7m. This was communicated to the developer and published in the preliminary information memorandum (PIM) in July 2009 ("the initial transfer value").
- The initial transfer value was updated to £182.2m ("the indicative transfer value") as a result of further information being available and continuing analysis. This updated calculation was communicated to the developer in September 2009. The indicative transfer value was published in the project information memorandum (IM).
- The developer submitted costs amounting to a proposed transfer value of £195.7m in December 2012.
- We have now reached a decision on the assessment of costs of £193.1m ("the assessed transfer value").

The key components of the initial, indicative and assessed transfer values are given in table 1below, followed by a summary of the reasons for movements between the indicative and the assessed transfer value.

Table 1: Summary of cost components

Category	Initial Transfer Value Jul 2009 (£m)	Indicative Transfer Value Sep 2009 (£m)	Assessed Transfer Value Feb 2013 (£m)
CAPEX	131.0	131.1	159.3
Development	42.5	38.2	27.3
IDC	13.2	12.9	4.5
Transaction	0.0	0.0	2.0
Total	**186.7**	**182.2**	**193.1**

CAPEX

The assessed transfer value CAPEX has increased by £28.2m. This included increases of:

- £2.0m for cable length and diameter design changes from 500mm^2 to 630mm^2 as the cable design was not fixed when the cable contract was placed and the was additional cable length needed after a more detailed survey of the cable route;
- £3.2m due to harder than anticipated soil conditions being encountered and trenching having to be carried out and an increase due to contractual waiting on weather costs having to be paid;
- £17.6m reallocated from project development to CAPEX; and
- £14.1m for the impact of exchange rate movements.

These increases were offset by reduction of:

- £0.3m for excluding infill radar study costs (as it relates to the projects generation assets) and for replacement batteries on the offshore platforms;
- £0.2m for spare 8 tonne rock bags not being transferred to OFTO; and
- several other items totalling £8.2m, including for example, a reduction in cable metal prices, the foundations contract, and other minor movements.

Development costs

The reduction in development costs is mainly due to the re-allocation of £17.6m of development costs to CAPEX, which is offset by increases in project management costs associated with project overruns and exchange rate movements.

Interest during construction (IDC)

The reduction of the IDC amount by £8.4m is a result of the developer re-setting their value of IDC from 4.3% to 2% for the duration of the project.

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 assessed them to be £2.0m.

Assessed transfer value for Sheringham Shoal

The assessed transfer value of the Sheringham Shoal transmission assets is £193,055,580.

1. The cost assessment process

Chapter Summary

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

Cost assessment principles

1.1. The cost assessment principles we have adopted in relation to various cost categories for TR1 and the reasoning for such principles can be found in the document 'Offshore Transmission: Guidance for Cost Assessment'[2] (hereafter 'the guidance'). We intend to apply these principles in our cost assessment process for all the 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.

Overview of the Transitional Round 1 (TR1) cost assessment process

1.2. 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.

1.3. The calculation of those costs shall be:

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

[2] Offshore Transmission: Guidance for Cost Assessment

incurred in connection with the development and construction of those transmission assets.

1.4. The remainder of this chapter details the process and principles that we apply to all transitional round 1 (TR1) projects, including Sheringham Shoal. Chapter 2 provides the detail as to how these have been applied to the specifics of the Sheringham Shoal project.

Data collection for TR1 projects

1.5. 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.

1.6. 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; and
- Transaction costs.

1.7. 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 for TR1 cost assessment

1.8. The cost assessment process for all of the TR1 projects involves the key stages set out below.

Initial transfer value

1.9. The initial transfer value calculated in July 2009 was based on cost submissions by the developer of each project. That value was made available to bidders at the Pre-Qualification (PQ) stage of the tender process. The letter we sent to developers at that time indicated that the calculation might be updated as a

result of any further information provided by the developer and our continuing analysis.

Indicative transfer value

1.10. In September 2009, we provided the indicative transfer value for the commencement of the Qualification to Tender (QTT) stage of the tender process. That 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 the calculation might be updated as a result of any further information provided by the developer and our continuing analysis. For all projects other than Barrow, that letter also provided comfort (subject to certain matters) that the minimum transfer value the developer would receive for the transmission assets once their project was completed would be 75% of the indicative transfer value.

Assessed transfer value

1.11. 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 commence an exercise to determine the assessed transfer value.

1.12. A draft of the cost assessment report, including the amount of the assessed transfer value, is 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.

1.13. The assessed transfer value is then 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 is published alongside the Section 8A licence consultation.

Final transfer value

1.14. The assessed transfer value is then used by the Authority to determine the final transfer value, which is confirmed once the Authority has determined to grant an offshore transmission licence to the successful bidder. After licence grant the final cost assessment report is published on the Ofgem website.

1.15. Ofgem normally finalises the assessment of costs prior to commencement of the section 8A consultation, with the section 8A Tender Revenue Stream (TRS) accounting for 100% of the final transfer value. Where the assessment of costs is to be finalised after commencement of the section 8A consultation, the section 8A TRS would continue to reflect the indicative transfer value.

1.16. Where the Authority completes the assessment of costs after the section 8A consultation and sufficiently in advance of Licence grant, the post tender revenue adjustment term (contained in amended standard condition E12-A3 of the OFTO Licence) (PTRA) may be utilised at Licence grant in order to enable a transfer of assets for 100% of the final transfer value. If, under exceptional circumstances, this is not possible then Ofgem may determine that deferred consideration would be paid by the OFTO to the developer on conclusion of our cost assessment and we would utilise a PTRA term after Licence grant to reflect the final transfer value. A provision to use the PTRA term post-licence grant would need to be included in the amended standard conditions to enable this to happen.

Cost assessment analysis for TR1 Projects

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

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

1.18. As a first test, we have checked the accuracy of the developer's 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.

1.19. To support the cost assessment process we have also undertaken a forensic accounting investigation. The scope of this investigation was shared with the developer 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 varies 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.

1.20. 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); and
- more relevant metrics for the allocation of shared service costs.

1.21. 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 incurred costs are economic and efficient

1.22. 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. We consider such approaches to be an important tool in assisting us in ensuring these costs are economic and efficient.

1.23. 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; and
- development cost as a percentage of transmission assets.

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

1.25. We have also considered the procurement processes adopted by the developer to obtain economic and efficient transmission asset costs. We have noted the differing procurement approaches taken by the developer 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.

1.26. 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. Sheringham Shoal cost assessment

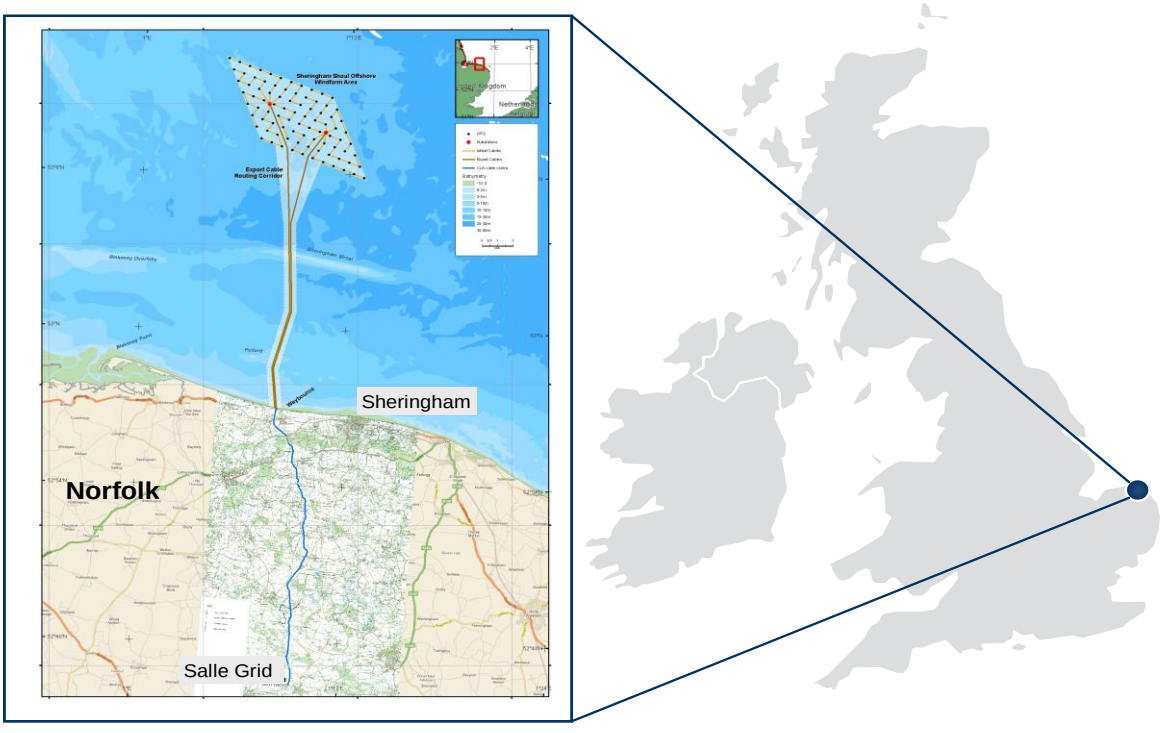
Chapter Summary

This chapter summarises how we have developed our cost assessment for the Sheringham Shoal 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.

Sheringham Shoal transmission assets

2.1. The Sheringham Shoal Wind Farm is located 17 to 23km off the coast of north Norfolk in East England, as illustrated in Figure 1 below. The Sheringham Shoal Wind Farm comprises of 88 wind turbine generators of 3.6MW output capacity. They are arranged in twelve strings, each containing seven or eight wind turbine generators. The total output capacity of the wind farm is limited to 315MW.

Figure 1 – Location of the Sheringham Shoal Wind Farm and Transmission Assets



Source: Scira

2.2. The developer of the Sheringham Shoal transmission assets and Sheringham Shoal wind farm is Scira Offshore Energy Limited. This is owned jointly by Statoil and Statkraft.

2.3. The Sheringham Shoal transmission assets connect to the Sheringham Shoal wind farm at two offshore platforms. The transmission assets that are transferring to the OFTO comprise of:

- two offshore platforms and associated substations;
- two subsea export cables with a total length of approximately 44km - one cable of approximately 23km and the other approximately 21km;
- two 132kV onshore cables which connects the wind farm to the regional; distribution network at the Salle substation, approximately 21.5km inland; and
- an onshore substation.

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

- Offshore: Located at the termination point for the 33kV infield WTG string subsea cables into the offshore substation 33kV Gas Insulated Switchgear (GIS); and
- Onshore: Located at the point where the 132kV GIS busbars in Salle will terminate at the disconnectors of the circuit breaker bays owned by UK Power Networks.

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

- 500m of offshore 630mm^2 cable;
- 500m of offshore 1000mm^2 cable;
- 5 offshore cable repair joints;
- 3.1km of 132kV onshore cable;
- 2 onshore cable straight joints;
- 4 onshore cable repair kits;
- 6 miscellaneous onshore cable joints; and
- 5km of 48 optical fibre cable.

Sheringham Shoal cost assessment process overview

2.6. 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. Set out below is an outline of the steps that have been taken in the cost assessment process for the Sheringham Shoal project.

- 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 (£186.7m) published.
- Aug 09: Further information received from developers and analysed by Ofgem.
- Sep 09: Indicative Transfer Value (£182.2m) published.
- Oct 09-Dec 12: Cost reporting updates performed with developer over the course of the construction of the project, up to the final cost submissions.
- Jan 13: Forensic accounting investigation undertaken.
- Feb 13: Closure on issues raised by forensic and technical consultants. Draft cost assessment report released to developer for comment and preferred bidder for information.
- Mar 13: Draft cost assessment report published alongside a consultation on the licence under section 8a of the Electricity Act 1989.
- Jun 13: 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.

2.7. The Authority will determine the transfer value when it determines to grant the licence to the successful bidder. The final cost assessment report will be published after licence grant.

Summary of Indicative Transfer Value determination

2.8. The initial transfer value calculated in July 2009 was £186.7m. 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 value stage. These were subsequently finalised and therefore considered in greater detail when the indicative transfer value was set.

2.9. We then established an indicative transfer value (ITV) of £182.2m in September 2009. The difference from the initial transfer value is as a direct result of the additional information being provided by the developer at the ITV assessment stage.

Process for determining the assessed transfer value

2.10. In chapter 1 we set out the two tests that were applied to the costs submitted by the developer for determining the assessed transfer value. These were to assess:

- the accuracy and allocation of the costs; and
- whether these costs were incurred economically and efficiently.

2.11. These two tests were applied to the developer's CAPEX, development, IDC and transaction costs submissions. In this chapter we identify the outcomes of applying these tests.

Accuracy and Allocation

2.12. The Sheringham Shoal project was constructed on a multi contract basis. A forensic accounting investigation was undertaken by our advisor, Ernst and Young 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 three main contracts in respect of the transmission assets, being the export cable supply, export cable installation, onshore and offshore substation contracts. We also checked that the costs 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 took into consideration the following:

- metrics used when allocating costs between generation and transmission;
- developer's submissions using our cost reporting template;
- the findings of the forensic accounting investigation; and
- cash flow payments related to the transmission assets.

Efficiency

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

- a benchmarking exercise undertaken by KEMA in 2009 across all transitional projects to help inform the indicative value and which was updated in 2010;
- a report on interest during construction by Ernst & Young; and
- the findings of the forensic accounting investigation by Ernst & Young.

Project specific issues

2.14. The Sheringham Shoal project experienced construction issues that have led to increased costs being incurred on the project, mainly in relation to the subsea export cables and the offshore substation installation. In assessing the costs for the project, we have discussed in detail with the developer:

- the causes of additional costs being incurred in connection with the cable procurement 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.

2.15. These issues are discussed in further detail in subsequent sections of the report.

Cost summary

2.16. Following completion of construction and development of the transmission assets, the developer submitted costs amounting to a proposed transfer value of £195.7m. 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 £193.1m. Table 2 below provides a breakdown of the changes in cost for the main components of the project between the initial, indicative and assessed transfer value.

Table 2: Summary of cost movements

Category	Initial Transfer Value Jul 2009 (£m)	Indicative Transfer Value Sep 2009 (£m)	Assessed Transfer Value Feb 2013 (£m)	Reasons for change between Indicative Transfer Value and Assessed Transfer Value (£m)
CAPEX	131.0	131.1	159.3	Increase due to : 2.0 for cable diameter design changes (increased cross section and outer diameter) and additional cable length after detailed survey 3.2 for hard soil conditions and waiting on weather costs Offset by decreases in cost for : -0.3 excluding infill radar and for replacement batteries on the offshore platforms -0.2 spare 8 tonne rock bags no longer being transferred to OFTO -8.2 various reductions such as cable metal prices, foundation contract, and other minor movements Note there is also a re-allocation of 17.6 from development costs and a 14.1 increase due to exchange rate movements
Development	42.5	38.2	27.3	Increase due to : 5.7 project management costs 2.7 exchange rate movements Offset by decreases in : -17.6 re-allocation of development costs to CAPEX -1.5 for allocation correction -0.2 for insurance allocation to generation
IDC	13.2	12.9	4.5	The developer capped their IDC rate to 2% from 4.3%
Transaction	0.0	0.0	2.0	Transaction costs have been added, which are assessed at the end of the cost assessment process
Total	**186.7**	**182.2**	**193.1**	

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

CAPEX

2.17. The CAPEX element of the assessed transfer value is £159.3m, which is £28.2m higher than the CAPEX element of the indicative transfer value.

2.18. Our advisors, Ernst & Young (E&Y) undertook a forensic investigation of the four highest value CAPEX contracts detailed below. These accounted for 48% of the total CAPEX costs submitted by the developer at the time the investigation was undertaken. In total this sample represents 49% of the assessed transfer value (excluding IDC and transaction costs). The CAPEX contracts investigated were:

- Installation of subsea cable (Visser & Smit);
- EPC[3] of subsea export cable (Nexans); and
- EPC of electrical systems infrastructure for onshore and offshore substations (Alstom – previously Areva).

Accuracy and allocation of CAPEX costs

2.19. For the majority of CAPEX costs incurred on the project, it was clear whether they should be allocated to the transmission or the generation assets in their entirety. Where costs were split between generation and transmission assets, the developer 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 in the initial, indicative and assessed transfer values.

2.20. Where the transmission element of shared CAPEX costs were clearly separable from the generation element, costs have been allocated by the developer on an actual basis. For example, the developer has allocated 2.9% of the supply and installation costs in respect of the foundations for the wind turbine generators and offshore substations to the transmission assets. The allocation is based on the numbers of foundations for substations relative to the number of foundations for the wind turbine generators. We consider that this is an appropriate allocation method.

Radar infill costs

2.21. The operation of a wind farm has the potential to disrupt the coverage of the Ministry Of Defence's radar. When developing wind farms, developers have to carry out studies to assess if the generator's turbine blades will block radar signals or cause

[3] EPC - Engineering, Procurement and Construction. This is a type of contract for construction projects

interference. The developer carried out these studies and it was subsequently agreed that the infill radar was not needed. The developer included a proportion of these costs in its cost submission.

Ofgem's view on accuracy and allocation of costs incurred

2.22. Radar issues arise as a result of the generation assets and their operational characteristics, so it is not appropriate for these costs to be allocated to the transmission assets. Therefore, we have not included costs related to the radar study in the assessed transfer value.

Spare 8 tonne rock bags

2.23. Following a programme of rock dumping to secure the integrity of the export cables on the outside of the substation foundations, there was a quantity of 8 tonne rock bags that were unused. The developer included an amount in their submitted transfer value for the proportion of the unused rock bags that were transferring to the OFTO.

Ofgem's view on accuracy and allocation of costs incurred

2.24. The developer is now proposing to not transfer these spare rock bags to the OFTO; therefore we have removed their cost from the assessed final transfer value, as it is not part of the assets transferring to the OFTO.

Reallocation of development costs to CAPEX

2.25. After the ITV was set in September 2009, further investigation of development costs noted that the developer had included their own commissioning staff's costs in development. After discussions with us, £17.6m was re-allocated to CAPEX based on a detailed study of how much time was going to be spent by Scira staff on commissioning work.

Exchange rate movements

2.26. In accordance with the cost assessment principles set out in the Guidance, if a developer has hedged its foreign currency contracts, we will use that hedge rate for determining costs. If the developer does not hedge, then the exchange rate must be based on the day rates applicable when the payments were made under the contract. Where the developer is unable to provide these daily rates, we will determine the rate based on the forward rates at the time that the contract approval was made.

2.27. Statoil, the lead developer for the Sheringham Shoal project, does not hedge its foreign currency contracts, as it has a wide currency exposure at group level. For this project, Statoil reported project costs at exchange rates used within the group at

the time of project approval by its board, and it had used these rates when reporting costs to Ofgem at the time of setting the initial and indicative transfer values.

2.28. Since the project was sanctioned well in advance of actual activity on the project itself, the exchange rate altered between the time of placing the contracts by the board and the time when payments were made under the contracts. Accordingly, we consider it would be inappropriate to use these previous submitted exchange rates as project rates.

2.29. Initially, the developer claimed its accounting system was unable to supply the spot rates at the time of each contract payment. On that basis, we decided to use the forward rates at the time contracts were approved. Subsequently, the developer asked to claim the difference between the project rates and the spot rates at the time of contract payment, and reverted with average daily exchange rates at the time of payment. We rejected this request on the basis that at that point in the process it amounted to granting the developer a free option on the currency risk (as the revised figures compared favourably with those under review), and it is unlikely that many of these currency transactions actually took place due to Statoil's natural currency hedge. The use of forward rates is consistent with our stated guidance principles, and the developer has accepted our viewpoint in this instance.

2.30. This use of forward rates has led to losses and gains on a wide variety of contracts; the net result is an increase to the indicative transfer value of £14.1m in CAPEX costs. The overall loss would have been £1.24m higher if we had used the developer's average daily rates at the time of contract payment. In using the forward rates prevailing at the time of contract approval, the total impact of exchange rate movements was reduced by £1.24m, across both CAPEX and development. This reduction was incorporated in the final cost submission by the developer.

Efficiency of CAPEX costs

2.31. We have reviewed the additional CAPEX costs submitted by the developer and we have decided not to include some of these costs in the assessed transfer value. This is on the basis that these excluded costs are not economic and efficient. We have detailed the main issues below and our reasons for excluding these costs from the assessed transfer value.

Export cable supply and installation

2.32. Additional costs were incurred from encountering harder than anticipated soil conditions, vessels waiting on weather and cable design options within the cable contract being exercised. We undertook further investigations to gain a better understanding of the issues and, to inform our views on whether the additional costs proposed by the developer were economic and efficient. The following sections expand on the nature of the Visser & Smit variation orders and the additional cable contract scope with Nexans and, our view on the efficiency of the costs incurred.

Events leading to extra cable supply costs

2.33. When the developer placed the order for the export cable with Nexans, some factors were unknown, including the exact cross section of the export cable required for the project. Cable manufacturing contracts typically have a long lead time (2 years), so the developer made the decision to sign the contract before the project was sanctioned to secure a cable production slot. This meant that the exact requirements for the cable were not known at the time that the order was placed; the cable was provisionally scoped at a cross section of 500mm^2. After further detailed cable studies were carried out, it was found that a 630mm^2 cross section cable was needed. Scira therefore exercised an option within its contract to increase the conductor size to 630mm^2. Nexans submitted variation orders for this contract option being exercised by the developer. This resulted in an increase of £1.4m to the cable purchase price.

2.34. Visser & Smit submitted variation orders for increased costs as a result of contractual vessel waiting on weather time payments; additional cable burial charges for unforeseen hard soil conditions requiring additional trenching; and, procuring and installing increased cable lengths due to variations from the proposed cable route. This last item was a result of having to change the cable route to avoid wrecks, unexploded ordinance and difficult seabed conditions not conducive to subsea cable installation.

2.35. Due to unexploded ordnance and the planned cable route impinging on areas of scientific interest, the cable route had to be varied. This resulted in one cable increasing in length by 1.04km and the other cable being 0.45km longer. The contractor claimed a variation order for payment on this addition work.

Ofgem's view on efficiency of costs incurred

2.36. We note the developer's approach to handling the issues that arose during the cable procurement process. They reacted to the potential delay caused by the long cable lead time by proactively ordering the cable in advance to secure a production slot. In managing the risk in the cable procurement process in this manner, and by including the options for the changes in the specification, lengthy (and likely more costly) delays were avoided. In the circumstances, we consider that the developer has demonstrated that they acted in an efficient and economic manner, and so we have included these costs in the assessed transfer value.

2.37. The additional costs for the cable length increase were due to unforeseen circumstances such as avoiding wrecks and unexploded ordinance. Under the terms of the cable installation contract, the developer is obliged to meet these extra expenses. In the circumstances, we consider that the developer has demonstrated that they acted in an efficient and economic manner and so we have included these costs in the assessed transfer value.

Additional costs for hard soil conditions

2.38. In the course of the cable laying, Visser & Smit encountered harder than expected soil conditions at the near shore area. This required the hiring of a backhoe trencher to assist in laying the near shore length of cable. The developer used their framework contract with Nexans to negotiate the hire of a trencher for Visser & Smit. This resulted in Visser & Smit raising a variation order for the cost of the backhoe trencher and additional associated costs.

Ofgem's view on efficiency of costs incurred

2.39. The developer had supplied all of the survey information that was required in the contract and the harder than anticipated soil conditions were unforeseen, so incurring the extra cost was unavoidable. We consider that the developer actively managed the situation to minimise the additional costs incurred. The contract with Visser & Smit meant that the developer was liable for the cost actually incurred in the cable installation. We consider that the developer has managed this issue in an economic and efficient manner. We have therefore allowed these extra costs to be included in the assessed final transfer value.

Additional costs for Waiting on Weather during cable installation

2.40. As a result of bad weather, delays were encountered by various cable installation vessels involved in the project. In order to meet its contractual commitments, the developer was obliged to meet these payments. The contingency that the developer had incorporated into its indicative cost submission contained an element of waiting on weather compensation and this has been allocated to cover this variation order.

Ofgem's view on efficiency of costs incurred

2.41. An economic and efficient way of dealing with bad weather delays is to allow for a statistical representative amount of bad weather days in the budget for a given contract. We consider that the developer acted to minimise these additional costs by liaising with their contractors and obtaining proof for each of these claims. On that basis, we have included the incurred costs in the assessed transfer value.

Waiting on Weather claims for offshore electrical installation

2.42. During the project, work undertaken during the electrical installation was not completed in line with the original schedule; work overran into late 2011. During the extended construction time, the electrical contractor experienced weather delays. The contractor claimed that the original delay was caused by circumstances beyond their control and claimed additional costs for the prolonged contract period. The developer has partially included this claim in their final cost submission.

Ofgem's view on efficiency of costs incurred

2.43. Having discussed this matter with the developer, we are of the view that on balance their rational for the treatment of a proportion of these additional costs is sound. Consequently we have part allowed the original submission, in line with our assessment of the economic and efficient level of these costs that should be incurred in developing and constructing these assets. This means that a proportion of the claim was not included in the assessed transfer value.

Replacement batteries for the Uninterruptable Power Supply (UPS)

2.44. The UPS is used to facilitate orderly shutdown of the wind turbine generators under grid loss conditions. They are used to power the control, safety and emergency systems and provide emergency lighting on the offshore platforms to facilitate safe exit of personnel. For this project the developer used a battery based UPS. It was discovered that the batteries on both offshore platforms were deficient and that they had also been deteriorating before installation on the offshore platforms. The developer is claiming the replacement costs under the warranties in its electrical system installation contract. The batteries have been replaced with new ones; however the electrical contractor is claiming that the cause of the failure relates to Scira's operation of the offshore platforms in the early phase of offshore installation and has billed Scira for the replacement batteries on the offshore platforms. The developer has included this in their submitted costs.

Ofgem's view on efficiency of costs incurred

2.45. Having discussed this matter with the developer, we are of the view that the economic and efficient way to treat this cost would have been to replace the faulty batteries under the manufacturer's warranty under contract. If, however, the blame for the failure rests with the developer, the cost of the replacement batteries is effectively an operational and maintenance cost. In the assessed transfer value, we only allow construction and development costs to be recovered. Therefore we have not included the cost of the replacement batteries in the assessed transfer value.

Development costs

2.46. The total development cost included for the Sheringham Shoal transmission assets in the assessed transfer value is £27.3m. These are costs incurred by the developer which were outside the scope of the main construction contracts. For the purpose of informing our cost assessment, our forensic advisors, Ernst & Young further investigated the project's development costs.

Accuracy and allocation of development costs

2.47. After the ITV was set in 2009, further information was submitted regarding the development costs. The developer had their own commissioning teams included in the development costs. This is a CAPEX cost and subsequently £17.8m was re-allocated to the CAPEX costs.

2.48. The other development costs for the project cover a variety of items relating to consultancy, legal, travel, land consents, 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.

2.49. When the ITV was set in September 2009, a ratio of 20:80 was used as a default for allocating shared costs between the transmission assets and the generation assets. The developer has applied this ratio to shared costs in their final cost submission.

2.50. We have reviewed and considered the rationale for this allocation and consider that the costs have been appropriately allocated, except for the insurance cost. The insurance costs should be allocated on the basis of the actual cost of the assets being insured. Therefore for the purpose of insurance costs, we have used the actual costs of the transmission assets against the generation assets and applied a 1:5 ratio. We consider that this is a more robust and justified cost allocation method and is also consistent with the application of our principles and the approach adopted in previous TR1 projects. This has lead to a reduction of £205k in the insurance costs allocated to the transmission assets.

2.51. In the course of the forensic review our advisors, Ernst & Young, identified an error in the allocation methodology used for some of the developers 'Management Team' costs. These costs included procurement, technical team, IT and project management. After reviewing our advisor's findings and discussing this with the developers, we have removed £1.5m of these costs that were apportioned to the transmission assets. As the costs related to the generation assets, they are not included in the assessed transfer value.

Efficiency of development costs

2.52. The development costs associated with the Sheringham Shoal project have been compared to the equivalent costs for previous TR1 projects. The total project management costs for the project at 14.1% of the total assessed costs, benchmarks in line with other TR1 projects.

2.53. The development costs have decreased relative to the value in the ITV by £10.9m. This is due to the re-allocation of £17.6m costs to CAPEX after the ITV was set. This re-allocation has been partly offset by an increase in project management costs, caused by the project duration and scope increasing. These increases in costs are examined in more detail below.

Additional costs for the increased duration of the project

2.54. There have been significant delays in the Sheringham Shoal project. This has extended the duration of the project and increased the amount of project management resource required and the associated increase in project management costs. These costs would not only be for Sheringham Shoal's internal project management labour costs but would cover costs for hiring external consultants and specialist contractors.

2.55. The first major delay was in respect of the contract to install the offshore substations and platforms and the wind turbine generators. The contractor, Master Marine, was building a vessel which was due to carry out 7 months work on this project, when civil unrest broke out in the docks where the vessel was being constructed. This caused unacceptable delays to the developer's project timetable and resulted in Master Marine and the developer agreeing to terminate the contract on terms acceptable to both parties.

2.56. Accordingly, the developer had to find and contract another installation vessel. The new contracted lifting vessel (from Seaway Heavy Lifting) had a different configuration and lifting spread from the previously intended vessel. This required a redesign of the lifting arrangements for the supporting slings and other items for the offshore platforms. The adaptation required the purchase of new equipment slings, shackles etc. The change in the vessel spread resulted in a delay and there was additional project management costs associated with this.

2.57. At an early stage of the project, the developer became aware of an industry-wide issue about the durability of the grouting in the transition pieces where they connected to the monopile foundations. This caused delays to the installation of the foundations while a solution was developed. There was additional project management time incurred for the contracting, fabrication and installation of this solution.

Ofgem's view on efficiency of costs incurred

2.58. We consider that neither the circumstances surrounding the requirement to arrange for a new installation vessel nor the industry-wide design issue on grouting of the transition pieces were foreseeable. The developer took prudent action in both cases to mitigate its losses and avoid longer-term issues with the project. On that basis, we consider that these additional costs of £5.7m can be included in the final transfer value.

2.59. There is also an increase of a further £2.7m related to forex movements in the development costs which has been included in the assessed transfer value.

Interest during construction

2.60. The total IDC calculated for the Sheringham Shoal transmission assets in the assessed transfer value is £4.5m, based on the developer's calculation of the interest rate to completion of the assets over a period from January 2005 to end of July 2011. The main changes from the indicative transfer value are a result of:

- the developer proposing a lower rate for IDC (2 per cent);
- 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

2.61. 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. For the assessed transfer value the developer provided an actual cash flow with the IDC ceasing in July 2011.

2.62. For the purposes of IDC, we consider that construction ceases once the transmission assets are commissioned[4]. The commercial supply of electricity to the transmission system which follows commissioning also indicates that the assets are complete and operational. Entitlement to IDC ceases when the assets are ready to transmit and so we have stopped the project's IDC at the end of July 2011. 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.

2.63. In relation to the date that IDC ceases, the developer included the final balance of the remaining spend on the project in the last month (July 2011) that IDC could be claimed. IDC is 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. IDC cannot be claimed after this point; the system had been commissioned, therefore the remaining project spend is not eligible for IDC. Consequently, we have disallowed the IDC from the assessed transfer value that was incorrectly claimed by the developer in relation to the remaining project spent.

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

Efficiency of IDC

2.64. The IDC rate submitted by the developer for the indicative transfer value was above the level that was submitted by the developer in its final submission.

2.65. 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 terminated in July 2011, which was earlier than forecast in the initial transfer value. The actual cashflow profile was also back-end loaded toward the end of the project, causing a further reduction in the IDC being claimed.

2.66. The IDC rate submitted by the developer is below our capped rates and is reflective of the developer's costs of financing the project. Further, despite the delays encountered at specific stages of the project, the developer has delivered the transmission elements of the project in an acceptable timeframe. Accordingly, we consider that the developer's submission for IDC that was incurred for this project is acceptable.

Transaction costs

2.67. The indicative transfer value did not contain any transaction costs as they were not known at the time. The developer has subsequently submitted a firm estimate of the costs they expect to incur to asset transfer. The total of these items results in the transaction cost element of the submitted transfer value being £2.0m.

Accuracy and allocation of transaction costs

2.68. 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

2.69. 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 5 below sets out a comparison of transaction costs for Sheringham Shoal compared to other projects:

Table 5: 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%
Sheringham Shoal	193.1	2.0	1.1%
Average			1.9%

2.70. The Sheringham Shoal project is the seventh project to be assessed in the first transitional tender round, so 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 rigid 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.

2.71. 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 Sheringham Shoal transmission assets.

Contingency

2.72. The assessed transfer value does 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

2.73. 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.

3. Conclusion

3.1. In conclusion, in accordance with Regulation 4 of the 2010 Tender Regulations, the Authority has assessed the economic and efficient costs which ought to have been incurred in connection with developing and constructing the Sheringham Shoal transmission assets to be £193,055,580.

Appendices

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Authority

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Capital Expenditure

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DECC

Department of Energy and Climate Change

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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

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