

Offshore Transmission Coordination Group (OTCG) - Fifth Expert Workshop

14 October 2011 - Meeting Note

Introduction

The expert workshop held on 14 October 2011 was the fifth in a series of workshops hosted by Ofgem and DECC to support the Offshore Transmission Coordination project.

The workshop aimed to build on discussions from previous meetings, by focusing on key asset delivery issues and their commercial impact, and key issues in determining the regulatory framework.

Workshop Overview

The workshop was hosted by DECC and Ofgem with the assistance of Ofgem's appointed consultants, TNEI/PPA energy, who have been engaged to provide analysis to support work stream 2 (asset delivery). The format of the workshop was as follows:

Part A: Generic network examples – key asset delivery issues and their commercial impact

- TNEI/PPA energy presentation on their work on asset delivery, and in particular, generic network examples
- Table based group discussion and report back

Part B: Key issues in determining the regulatory framework

- Ofgem presentation on key issues in determining the regulatory framework, with a focus on Anticipatory Investment (AI) and Network Optimisation
- Table based group discussion and report back

Outputs

This note reflects the Secretariat's summary of the views expressed at the workshop and should not be considered to reflect the views of either DECC or Ofgem. Appendix 1 lists the organisations that participated in the workshop.

Part A –Asset Delivery

Introduction

Graeme Bathurst, TNEI/PPA, gave a short presentation covering the methodology of the asset delivery workstream, generic examples of different issues with coordinated offshore network configurations, and consenting considerations. Following this, participants were asked to consider the following questions:

1. What are the key commercial impacts that result from these asset delivery issues relating to coordinated outcomes?
2. How would these issues impact on the economics of the generation project? Which would be most important?

Summary of discussion

Whilst there was general agreement with the approach being taken by TNEI, there was some disagreement as to which generic example represented the base case of what is the most likely scenario to emerge under the current regulatory framework. This hinted at the challenges in finding commonalities in views on commercial risks between generators, and conclusions on asset delivery.

There was general agreement that the most fundamental issue which needed to be resolved was who carries the risk of stranded assets. Generators would have concerns if required to carry this risk or if required to indemnify an OFTO for delivery of those assets.

A number of stakeholders were also keen to learn who would take the risk of design and development of transmission assets associated with anticipatory development if a number of parties are involved, what the process would be for reimbursement, who would pay, and what the incentives would be for them to do so.

A number of comments were also made in favour of there being a central design authority to ensure that the coordination of the grid proceeds in an efficient way, and that there be a sufficient level of technological standardisation. However, any proposed treatment of anticipatory investment, potentially through Ofgem's assessment of the asset transfer value, was viewed as a more crucial topic.

A number of stakeholders expressed their concern that under a coordinated network, developers would be more dependent on other parties, which is something they have little experience of currently, and that there would need to be a sufficient cost saving to ensure that this was a risk worth taking.

In terms of other relevant issues impacting on the economics of a project, some participants mentioned the likelihood of a firm versus non-firm offers for export capacity.

Part B –Key issues in determining the regulatory framework

Introduction

Jon Parker, Ofgem, briefly reiterated the key question that DECC and Ofgem are considering as part of this project: how can we ensure that the development of offshore electricity infrastructure best facilitates the delivery the Government and Ofgem’s objectives now and in the future?

He referred to an updated problem statement as set out in the slides accompanying the presentation, and noted that DECC and Ofgem are closely considering each of the issues, but that this workshop would focus on the possible barriers of Anticipatory Investment (AI) and Network Optimisation.

After briefly outlining some of the key issues related to these two barriers, participants were asked to consider the following questions:

Optimising the network

- Are there improvements that can be made to the connection process to help deliver the most economic and efficient outcome?
- Are there improvements that could create a better vision/roadmap of how the network might evolve to better inform developers/OFTOs/wider stakeholders?

The process for handling anticipatory investment

- What would be the most efficient and effective allocation of the stranding risk resulting from AI in different coordination examples?
- What would be the key design issues in implementing an AI process?

Summary of Discussion

Optimising the network

In terms of the connection process, it was suggested that if a generator is made an offer that results in more costly solutions, then this is a false choice. Some commented that NETSO’s attempts at developing an efficient network by moving connection offers needed to be balanced against the risk of increasing costs for generation projects. It was also noted that achieving agreement between developers on shared connections was difficult, as developers are reticent to share information about their connection offers with other developers unless it is in their commercial interest to do so.

A repeated comment, in terms of improvement to create a better vision/roadmap of how the network might evolve, was that it is useful to have a vision as a starting point (and ODIS does this to some degree), but that changes could be made to produce a document that is more holistic in its view of onshore and other offshore developments. It could, for example, take into account the Seven Year Statement (SYS) and Electricity Networks Strategy Group (ENSG) work. This would also help with the EIA process.

However, several stakeholders strongly suggested that such a roadmap cannot and should not be a blueprint of what needs to be built, given the changes that are continually being made (even to a document like the SYS).

Greater stakeholder consensus on projects in larger zones could be treated such that shared development costs are regarded as sunk for the greater good.

The process for handling anticipatory investment

AI is possible through the current regime, and would be assessed through the ex-post cost assessment process, but given the uncertainty associated with this, there might need to be more attention given to an ex ante process. The Transmission Investment Incentives (TII) regime was suggested as a useful proxy – with the use of gateways and tests to provide certainty on what costs can be recovered.

Some participants suggested bringing forward a real project as a case study to help develop and test an AI process. It could be led by developers partnering with the NETSO, as a joint-venture of sorts, and analogous to what occurs in Scotland where the NETSO works with the incumbent TOs (in this case, a developer).

Others suggested that the AI process could be treated in two stages, with approval for low cost, pre-construction work coupled with advance certainty of funding for the AI of the delivery work. There was discussion as to whether AI is considered up front through, for example, approval of a business case or is ex-ante with specified criteria that, if fulfilled, could provide some form of guarantee on what can be recovered. It was agreed that more - effort should be weighted toward proving the needs case on construction costs although it was important that development costs, which take up around 5% of the total project costs, be recoverable. Some participants suggested sharing of development costs with The Crown Estate which could also assist with the coordination of projects.

For some participants, the key questions came down to 1) who takes what decisions, and 2) how is it financed or incentivised? There was a suggestion as to how improvements to the current process could be made more iterative – for example, the NETSO could suggest a coordinated outcome to a number of developers within a zone. In case of disagreement between developers within a zone as to how to proceed with a coordinated proposal, whilst there was no appetite for the NETSO to overrule any party, one option could be to socialise the additional costs of the coordinated outcome.

Other key design issues included:

- Taking into account development timetables – for example, long lead times for procurement of parts with developers making commitments for Round 3 projects in the near future.
- The AI process needs to be clear and certain to encourage developers to think ‘bigger picture’, as ultimately it is company boards which will approve what projects go forward.
- Congruence with the consenting process – as having approval for AI does not guarantee any planning approval.
- There should be an incentive to move from TNEI’s generic examples (3) to (1) as a more efficient choice.

Appendix 1: List of participating organisations

1. Alstom Grid
2. Balfour Beatty
3. Centrica
4. CG Power
5. EDF Energy
6. EDP Renewables
7. Green Alliance
8. Jacobs
9. JNCC
10. Mainstream
11. Mott Macdonald
12. Nabarro
13. National Grid Electricity Transmission (representatives on behalf of TO and NETSO)
14. National Grid Offshore Ltd
15. Paradigm Change Capital Partners LLP
16. RenewableUK
17. RES Offshore
18. RWE Npower Renewables
19. Scottish Renewables
20. ScottishPower Renewables
21. Siemens
22. Siemens
23. Statoil
24. Suffolk and Essex coalition of amenity groups
25. Suffolk County Council
26. The Crown Estate
27. Transmission Capital