Airtricity response to "Licensing offshore electricity transmission – a joint OFGEM/DTI consultation"

Whilst this response has been submitted in Airtricity's name, it also represents the views of the Greater Gabbard offshore wind farm project and its shareholders and advisers.

Chapter Two – Regulatory Options

Question 1: Which option do you favour and what are your reasons for doing so?

Airtricity does not specifically favour either of the two proposed approaches but believes that, although there are advantages and disadvantages of each option as outlined below, both could be made to work.

Issue	Exclusive approach	Non-exclusive approach
Competition to become TO	Likely to be restricted to incumbent TOs	Smaller and better defined role may encourage more participants
Effect on developers	Should know who TO is early on in offshore wind farm development timeline	TO may be appointed later in offshore wind farm development timeline – may have impact on timescales
Effect on no. of equipment suppliers	Incumbent TOs likely to stick with existing main suppliers	New TOs may bring more suppliers into the market
Effect on supplier's costs	Business as usual	May push up supplier's tendering costs or suppliers may restrict to whom they tender
Effect on transmission costs	Less incentive to reduce transmission costs and therefore transmission charges	Should lead to reduced transmission costs
Effect on transmission planning coordination	Single TO for an area should ensure cost synergies and efficient designs are captured	Would require more coordination from GBSO
Modifications from offshore wind farm developers	Dealt with through normal modification process	Possible price re-opener or requirement for re-tendering TO role

Whichever option is chosen, there must be no chance of there being no TO available to construct and own the assets.

If the exclusive approach is used the licensed TO must have an obligation to offer terms to GBSO for the provision of transmission service in the area covered by its licence. If no TO comes forward in the competition for an exclusive TO licence in a particular area then there must be a fall-back option for a non-exclusive approach.

In the non-exclusive approach, each developer should have the option of taking part in the competition and of therefore being its own TO (see Question 5 below).

Question 2: Do you think that the approaches which have been ruled out should be considered further and are there any other approaches that should be considered?

Airtricity does not believe that the approaches which have been ruled out should be considered further and does not believe that there are other approaches that should be considered. It is important that this consultation exercise is brought to a timely conclusion so that some certainty in the regulation of offshore transmission can start to be established.

Question 3: Should anything further have been taken into account in assessing the options?

Airtricity believes that all material and relevant issues have been taken into account.

Chapter Three – Practical issues for consideration under both non-exclusive and exclusive licensing approaches

Adoption

Question 1: Could providing anything further, beyond the comfort already provided by OFGEM, be justified for projects that will be constructed or have secured financial close prior to the award of offshore TO licences.

Airtricity has not altered its views on the "adoption" measures necessary in order for projects to reach financial close and as set out in the adoption group first paper dated 1st August 2006 (reproduced in Appendix A for information).

Airtricity believes that an exemption to the requirement for an offshore Transmission Licence (with the opportunity to opt into the enduring arrangements) is the quickest and simplest way to remove the legal and financial uncertainty that surrounds the introduction of an enduring licensing regime for offshore electricity transmission.

Is important to stress that without any additional measures from OFGEM/DTI in this area then it is very unlikely that second round offshore wind farms, and certainly those using non-or limited-recourse project finance, will be able to commence construction

before both an offshore TO has been appointed and there is clarity regarding the calculation of the TNUOS charges that will be levied on these projects. The resulting delay would mean that second round offshore wind projects could not contribute to the government's target of 10% of electricity from renewables by 2010.

The adoption group was established at the behest of OTEG to provide a consensus view on this issue, the group included developer representation from Airtricity, Eon, Centrica, RWE npower, Warwick Energy as well as TO representation from ScottishPower and SSE. There have been no subsequent papers as the group has neither received any detailed comments on the first paper nor received requests from OTEG for any further information. As such the adoption group first paper still stands as the consensus view on measures necessary, and the timing of them, in order for projects to reach financial close.

It is Airtricity's view that the proposed Class Exemption order for Offshore Distribution does not materially affect the adoption issues as outlined in the adoption group first paper as very few, if any, second round offshore wind project connections will be classed as offshore distribution post-commencement of section 180 of the Electricity Act.

Question 2: Would a departure from OFGEM's current approach to the adoption of assets be justified or would different treatment be unduly discriminatory.

Airtricity's view is that departure would be justified on the grounds described above and on the basis that it would be an interim measure whilst enduring regulatory arrangements are being established. It was clear from the consultation workshop held on 29th November 2006 that no parties would regard this as discriminatory and presumably responses to this consultation exercise will bear this out.

Practical issues for consideration under the non-exclusive licensing approach

Question 3: What are your views on the potential costs to TOs of bidding to build, own and operate offshore assets ? Do you have views on how such costs might be minimized?

Airtricity has not evaluated this question.

Question 4: Do you believe there is a risk of a lack of co-ordination that is specific to the non-exclusive approach? If so, how serious a problem do you believe this is? To what extent could the suggested measures or any other measures mitigate such a risk?

The paper by Lewis Dale on "The co-ordination of offshore network development" is a useful summary with respect to the risks of a lack of coordination. The actions that the paper highlights are that development of standards should be actively progressed, and that guidelines for offshore surveys and preliminary engineering work should be developed. These are activities that could be undertaken by GBSO in a coordinating role under the non-exclusive approach. The third issue the paper notes is that of the risks of additional investment and is equally an issue for the exclusive and non-exclusive approaches.

The paper therefore highlights that there would necessarily be a greater coordination role for GBSO under the non-exclusive approach than the exclusive approach.

It would not be appropriate to introduce a window for applications from offshore generators as this would introduce unnecessary and artificial delays into project development timelines unless it was aligned with offshore wind farm site awards (see response to question 8 below). However, even this would be problematic as experience has shown that it is highly unusual for a single connection application to be sufficient and that major projects tend to go through a process of design and program evolution requiring multiple modifications to connection agreements.

Question 5: Is it appropriate to allow generators to bid to provide their own transmission services, in particular in the light of any potential moves towards unbundling at an EU level?

Airtricity believes that ownership unbundling of transmission activities from generation and supply activities is preferred. However, there has been no decision to take this step at an EU level and there appears to be considerable opposition to it.

It would not be appropriate to restrict generators from bidding to provide their own transmission services if other companies that had affiliates that held generation or supply licences, were allowed to bid. For example it would not be appropriate to restrict Greater Gabbard Offshore Winds Ltd from bidding to provide its own transmission services but to allow one of the onshore TO licence holders that has a generation affiliate to do so.

Question 6: How can confidence be built that the tender process can be run transparently and fairly and to what extent can the proposals outlined in this chapter (3) ensure this?

The tender process should build on experience gained in the PPP/PFI sectors. A tender panel independent of the GBSO would ensure fairness.

Question 7: Is it appropriate to have certain defined re-openers in a fixed-price bidding system?

It would be appropriate to have re-openers where certain risks could not be managed or quantified by the prospective TO and where therefore prospective TOs may price these risks highly. Areas where this may be appropriate include:

- validity of information provided to prospective TOs, particularly where there is a material cost impact
- ground conditions where prospective TOs have not had access to properly specified and conducted ground surveys (including seabed)

- consents risk
- political and regulatory risk (e.g. change in law)
- changes to designs or programs as a result of modification applications from offshore wind farm developer (or could require retendering)

Practical issues for consideration under the exclusive licensing approach

Question 8: How should the geographic extent of exclusive regional licence areas be defined? What is the appropriate balance between obliging exclusive offshore TOs to assume unknown levels of risk and the need for a wider geographic area to ensure a TO is available to connect generators? Is it appropriate to make available three offshore TO licences that cover the three strategic areas and to leave the remainder of the offshore area unlicensed until the need for new licensees arises?

If the exclusive regional licence area approach is decided upon, the most logical approach would, initially at least, be to align the boundaries of these areas with the areas of the round 2 Strategic Environmental Assessments (SEA) specified by The Crown Estate. This would capture all offshore wind farm connections existing or planned at 132kV and above. There would be little point in awarding TO licences for outside of these areas until The Crown Estate/DTI has decided whether, when and how it will award further offshore wind farm development rights.

If a similar process is envoked for offshore wind farm site awards as for round 2, future TO licence areas might also line up with further SEA regions defined by The Crown Estate/DTI and TO licences could be awarded in parallel, or shortly after, the process to grant offshore wind farm development rights in these areas.

Question 9: On what basis should the competition for offshore exclusive TO licenses be run?

Clearly any TO must have the capability to fulfill its duties as a TO, and its ability to carry out its duties as a licence holder should be a continuing requirement of holding a TO licence. Credit worthiness and relevant experience should be hurdle criterion rather than the basis of competition.

Cost competition could be incorporated by prospective TOs bidding rates of return (cost of capital), actual costs would still need to be efficiently and economically incurred and would be subject to this test. However, this does highlight the key problem with the exclusive approach – that of how pressure is maintained to keep costs down once the licence has been awarded.

Question 10: what is the value and feasibility of benchmarking exclusively licensed offshore TOs and in what way could this be facilitated if desirable?

Benchmarking is an essential part of maintaining a workable proxy for competition in an exclusive approach. Although each exclusive TO will have its own particular challenges, solutions and working practices, this diversity will enable useful comparators and cost benchmarks to be established. Initially benchmarking will necessarily be primarily an information gathering and analysis exercise, due to the lack of experience of offshore TO networks in the UK and the likely "early stage learning" that will occur. However, capturing this relevant information at the start of a regime will enable reasoned judgements to be made as to the appropriate time to modify and develop incentives and performance measures for incumbent TOs as the sector moves from intial to more regular operation.

The development of Benchmarking criteria may be assisted by the experience already gained in the offshore oil gas and telecommunication industries, who face many of the same challenges.

Question 11: How can suitable incentives be placed on exclusive offshore TOs to ensure that assets are constructed and operated economically and efficiently? Is there an alternative to simply passing through costs which raise the charges paid by consumers and generators? Would it be suitable to use international benchmarks as a means of assessing economy and efficiency?

This is clearly a disadvantage of the exclusive option. Whilst offshore TOs do face different challenges to those onshore, the regulatory mechanisms which have been developed, refined and tested to ensure that onshore assets are constructed and operated efficiently should be transferable with minimum difficulty to an exclusive offshore regime. These include appropriate penalties (on the TO) for inefficiency and incentives for innovation, performance/service levels and "beating" targets. As noted in Question 10 above, there are suitable benchmarks to be derived not only from international experience, but also from industries which have congruent challenges.

There is likely to be a need for the form of price control to evolve as experience is gained. There will need to be provision for a more flexible approach in the initial stages such that legitimate unavoidable cost pressures do not cause "reopeners" but are assessed against sensible cost pass through parameters. As experience is gained, it will be appropriate to develop the form of the price control to encompass a more incentive based approach (including the use of benchmarking).

Question 12: What arrangements would be appropriate for dealing with future build outside of exclusively licensed areas?

From a developers perspective the important issue is that there would be an offshore TO appointed within a reasonably short time period of the developer gaining offshore wind farm site award. Whatever the process for site award it is likely that the The Crown Estate and/or DTI/DEFRA would require that it was preceded by some form of SEA (as a requirement under the SEA directive – although no other EU member state seems to have considered the need to do this for offshore wind farms to date). It would be appropriate to appoint new offshore TOs to align with SEA areas after each SEA had been completed.

See also answer to question 8.

Question 13: How can generators be provided with timely, firm offers within reasonable timescales under the exclusive option?

It is important to recognize here that under both options offers will be made to offshore wind farm developers by the GBSO and not the offshore TO.

It is still clearly preferable for there to be an obligation on the GBSO to make an offer to the customer within a defined timescale. Given the advent of shallow connection charges, and given that Use of System charges are not based on specific asset costs, the charges in a connection offer are likely to be based on the location of the offshore wind farm only, and not the specific costs of connecting it to or reinforcing the transmission system.

It may be useful for the GBSO to produce estimates of UoS charges for particular areas as part of any SEA process for potential offshore wind farm sites.

As part of NGC's ongoing review of user commitment, from April 2007, a new commitment regime will come into force. This is not asset specific but is based on TNUoS multiples. User liability will therefore be fully calculable at an early stage.

The other key factor in any connection offer is program – this will depend on preferred onshore connection point and any need for onshore grid reinforcement. This is currently evaluated during the three month offer period.

Airtricity believes that the GBSO should be in a position to provide firm offers within similar timescales to onshore applications under either the exclusive or non-exclusive options.

<End>

Appendix A – Adoption paper

1 August 2006

Adoption group
First paper

Introduction
This paper sets out the rationale for and requirements of developers with respect to the "adoption issue" and also provides a Transmission Owners (TO) perspective on the issue. This paper follows a meeting of the Adoption group (the group) on 26th July 2006 and is supported by all those at the meeting[1].

Whilst this paper does not seek to differentiate between whether the offshore transmission would be connected to onshore transmission or distribution, it is recognised that there may be additional considerations or complexity in the latter case.

Importance of adoption issue
The group wanted as a whole to express the seriousness and importance of the adoption issue and the consequences of not addressing it adequately.

The government has set a target of 10.4% of electricity coming from renewable sources in the year 2010/11. In order to meet this target at least one or more of the second round offshore wind farms in the UK will need to be operational by 2010. The economics of offshore wind are still considered by the majority of developers to be marginal under the current renewable support mechanism and with the current offshore transmission regulatory regime. One of the main stated reasons behind the decision to extend the regulatory arrangements that cover onshore transmission to also cover offshore transmission is the benefit that this would bring in reducing initial costs to offshore wind farms and thereby in enabling offshore wind farms to be developed and constructed in order to contribute towards meeting Government targets.

However, the extension of the regulatory regime offshore has introduced uncertainty at a time when early developers will shortly be seeking to finance their projects. The main areas of uncertainty are:

- Will the offshore transmission be adoptable?
- If so will the developer and its investors recover all the costs it incurs if they are adopted and to what level of charges will the offshore wind farms be exposed?
- What will happen if the assets are not adopted by a third-party TO?

This uncertainty gives rise to fundamental issues to investors in these projects which if not resolved are likely to delay the construction of early round 2 projects. Debt investors in particular seek to adopt a very low risk approach to their investment as they earn only a small return over the risk-free rate. Their approach to these issues and the uncertainty

[1] These included five developer representatives, two TO representatives and a manufacturer representative

they give rise to will be either to require more equity to be invested in a project, thereby diluting the return on equity and making is less likely to proceed, or to refuse to lend at all. Equity investors may accept more risk, but even so only up to a limit.

For example:

i) A project will not proceed if there exists a risk that the transmission of electricity offshore becomes a prohibited activity without a licence, and no licenced TO is forthcoming to adopt the offshore transmission assets of the project, nor is an exemption to the requirement to have a licence granted;
ii) It will only be possible to get low levels of debt, if any, into the offshore transmission element of a project if there is uncertainty regarding the level of costs recoverable on adoption, or indeed whether adoption will occur at all;
iii) Higher levels of debt will not be achievable if there is no cap on the expected level of transmission charges payable.

These are issues that will have a serious impact on the financing of projects, and will cause delay to projects proceeding to construction unless they are resolved before the end of 2006.

Exemption

Many, if not all, of the risks associated with the enduring regime, could be mitigated by giving legally binding comfort to early developers that if they so desired, they would receive an exemption from the requirement to have a licence for the transmission of electricity from the offshore wind farm. There is at least one project already built that has an offshore 132kv line, and so will be affected by the new arrangements, therefore this aspect will have to be addressed whatever happens to other projects.

Developers would still be incentivised to ‘opt in’ to the enduring regime by the expected cost reduction, and which as noted before is one of the main stated aims of the enduring regime. Indeed it is important that developers would have the right to opt in, so as not to be disadvantaged by being amongst the first to construct.

It may be that OFGEM alone cannot give the assurance of an exemption, as it does not yet know the precise form of the legislation prohibiting transmission of electricity offshore without a licence, and therefore whether it will have the power to grant an exemption to the requirement to have a licence, and therefore this course of action may also require legally binding comfort from the Secretary of State.

In the event that this blanket assurance cannot be given, then more detailed legally binding comfort would be required as below.

Issues that should be advanced to provide further clarity

The group has highlighted certain areas that if progressed urgently would provide greater clarity as to the acceptable design of offshore transmission assets to be subsequently adopted:

- SQSS – the group acknowledges that this is being progressed rapidly
- Ownership boundary – in particular whether offshore substation foundations will be owned by TOs (and therefore the adopted design of which would be subject to an efficiency test) or by generators
- Design life
- Point of Grid Code compliance – developers assume that applying the current Grid Code requirements at the point of onshore connection is satisfactory
- Overhead v underground and the trade-off between the need to construct renewable generation quickly versus the extra costs of underground cables
- Non-electrical technical requirements (e.g. cable burial specifications, foundation design requirements, health & safety requirements)

The group recognised that it was unlikely that all of these issues would be resolved prior to the first projects reaching investment decision and therefore that a process would be required to give comfort on designs in the absence of full standards and specifications being available. This process should allow for permanent derogations to enduring standards when the design has been fixed prior to those standards being established.

Issues that require further certainty or comfort if certainty of exemption cannot be given

These fall into four categories:

1) <u>Process for the adoption of assets by a subsequently appointed licensed TO</u>

It is not in the interests of any party, from either an economic or an environmental perspective, for inefficient expenditure on offshore transmission assets to take place. It is therefore incumbent on all parties, as far as is reasonably possible, to ensure that this is avoided.

However, in order for any investment to take place, it is necessary for developers and TOs to have a degree of certainty around what is likely to be considered by OFGEM as efficient. Increased certainty could be provided if there were some mechanism that allowed OFGEM, supported by technical consultants as necessary, to make an economic and technical assessment of high level designs and forecasts costs in advance of investment actually taking place. In many cases this assessment will need to be made in advance of the development of the price control framework in order to avoid unnecessary and lengthy delays to construction. Such an assessment would form an important part of any adoption process.

There is precedent for such an assessment within the current framework for onshore transmission. In developing its TIRG proposals (Transmission Investment for Renewable Generation) OFGEM and its consultants SKM carried out an economic and technical assessment of a number of potential transmission upgrades. The final proposals clearly categorised some projects as efficient and provided a mechanism under which, subject to future efficiency tests and delivery of agreed outputs, these projects would be funded.

The main characteristics of the TIRG mechanism are summarised as follows:

- 'baseline' costs agreed in advance following economic/technical assessment by OFGEM and its consultants;
- comprehensive cost reporting regime during pre-construction and construction phases of the project;
- provision for movements in costs (increase or decrease) during pre-construction and construction phases to be assessed and for cost baseline to be amended;
- incentives for TOs to minimise actual investment; and
- RAV to be determined based on actual costs determined by the Authority to be efficiently incurred.

The size of the investment on offshore transmission assets that will be required to facilitate many of the offshore wind farms is comparable with the TIRG investments. As such it would appear entirely appropriate that this established onshore precedent be extended to offshore.

The process outlined above is similar to that suggested by BWEA in its paper entitled "Adoption of transmission assets". The additional points that the group wished to add were:

- There was scope for early designs to be not suitable for adoption by prospective third-party TOs and that this situation needed to be covered
- As outlined above the ownership boundary needs to be defined
- Developers would require comfort that all efficiently incurred costs incurred in establishing the offshore transmission assets would be recoverable including:
    - Development costs (inc. seabed survey costs)
    - Real Estate costs
    - Construction costs
    - Financing costs
- Developers would require comfort that as well as all rights in relation to the offshore transmission assets being adopted, all liabilities would also be adopted

2) <u>The mechanism for transferring statutory consents to a subsequently appointed licensed TO</u>

Consents where they do not reside with the asset may in some cases need to be reapplied for by new TO, (an example of this is the licence required under section 5 of the Food and Environment Protection Act 1985). The inability of a new TO to obtain the consent may result in a third party TO not being appointed. However, it was noted that these consents are largely in the control of DTI or DEFRA and who were therefore in a position to give comfort on this issue.

3) <u>Clarification of the legal position in the eventuality that there is no subsequently appointed third-party licensed TO</u>

Whilst developers recognise that it is unlikely that there would not be a third-party TO forthcoming to adopt assets, it clearly is a possibility due *inter alia* to:

- Detailed design not being acceptable to prospective TOs
- Consents not being obtainable by prospective TOs
- Commercial risk/reward balance not being acceptable to prospective TOs

Given the likelihood that the transmission of electricity from offshore wind farms to shore will become a prohibited activity without a licence, investors in offshore wind farms will not accept the risk of a situation occurring whereby no third-party TO is forthcoming, if there is not absolute certainty that in this circumstance either:

- An exemption would be granted to the offshore wind farm; or
- The developer would receive a TO licence

The group discussed a third option of a "TO of last resort" which had to accept the role if no other third-party TO was forthcoming but it was thought unlikely that any party would accept this role.

Most developers in this circumstance would prefer to have an exemption.

However, as stated above it maybe that OFGEM alone cannot give this assurance. To cover this situation developers would require legally binding comfort from OFGEM that in the event that an exemption was not possible, an offshore transmission licence would be granted to the developer on a project specific basis and that its price control would allow it to recover all its efficiently incurred costs over a 20 year period (forecast life of the offshore wind farm).

4) Clarification of the maximum transmission charges likely to be levied on an offshore wind farm owner following adoption of assets by a licensed TO

As noted earlier a main stated benefit of the regulated regime is that the initial costs to be borne by offshore wind farm developers would be reduced as a result of the regime. Some certainty in this area is required if early developers are not to have to cater for large variations in possible connection and use of system charges, and therefore not to be actually disadvantaged by one of the aspects of the regime that is meant to promote the early deployment of offshore wind farms. Therefore developers would require legally binding comfort from OFGEM that the connection and use of system charges that they would pay under the enduring regime would be no more than the equivalent costs under the existing regime.

Process for obtaining the necessary comfort

The group considers that there are two possible routes to give sufficient certainty to early developers to allow them to proceed without delay:

i) the Secretary of State and/or OFGEM give a legally binding comfort in a letter that early developers will have the option of an exemption (with the right to opt into enduring arrangements); or

ii) OFGEM gives a legally binding comfort in a letter setting out, as outlined in this paper:
   - The process for agreeing design and costs prior to commitment, and dealing with any variations during construction
   - How the situation of no third-party TO coming forth is dealt with
   - Certainty on the maximum level of costs to be charged to offshore wind farms for transmission.

Given the timescales, the group recommends that these options, together with draft comfort letters, are set out in the October consultation document.

The Transmission Owners' perspective

A fundamental point from the TO perspective is that the regulatory framework adequately funds whatever is adopted in terms of the initial and ongoing costs, including potential liabilities around decommissioning. Other concerns relate to the following issues:

- the extent to which the adopted assets enable the TO to comply with its licence obligations and associated codes (Grid Code, STC etc.);
- compliance with conditions of planning consent and robust landowner agreements, leases, wayleaves etc.;
- the ability to operate assets/network in safe manner consistent with appropriate legislation and accepted industry safety procedures and rules; and
- equipment fit for purpose, installed to specification/manufacturers instructions with appropriate warranties and servicing agreements in place.

A clear process for adoption is considered to be in the interest of all parties including potential TOs. Accordingly the existing TOs are fully supportive of the need for a process to be established and documented as soon as possible.

Adoption must be by agreement. It will not be acceptable for the process to place an obligation on a TO to adopt assets where the costs and potential liabilities are not adequately funded. The possibility therefore exists where no TO will be willing to adopt a set of assets. However it is considered that early clarity around the adoption process can minimise this as a possibility. It must also be emphasised that there may be circumstances where additional expenditure is required on offshore transmission assets to ensure that a TO is prepared to adopt and operate them over their lifetime. If the TO is required to make this expenditure then this must be fully recoverable under the price control and regulatory framework.

Timescales

The group proposed that the timescales for resolution of this process should include:

Oct '06: treatment of this issue in the October consultation document as outlined above;

Dec ’06: issue comfort letters to those developers that require it to enable their investment processes to proceed.

The group considers that given the importance of this issue in allowing early round 2 projects to proceed and to contribute to the 2010 renewables target, that the OTEG process should formally recognise the steps being taken to address this issue in its timetable.

<Ends>