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Dear John

Licensing offshore electricity transmission – a joint Ofgem/DTI consultation

I am writing in response to the above consultation document which considers the options for licensing transmission connections between offshore generating stations and onshore electricity networks. The consultation sets out two options for the licensing regime: a non-exclusive licensing option whereby TOs would compete to build, own and operate defined transmission assets, and an exclusive licensing option whereby a number of regional monopoly TO areas would be established and licenses awarded by means of a competitive process.

In principle, Scottish and Southern Energy does not support either of the preferred approaches to exclusive and non-exclusive licensing set out in the consultation paper. We have three key issues with the proposals. Firstly, we do not believe that the costs and benefits of the proposed approaches – and, further, those of the alternative approaches that have been ruled out – have been clearly identified and quantified. Secondly, we believe that both preferred options are overly complex and difficult to understand. Finally, we believe that both approaches would raise issues with regards to common access and interoperability of the transmission system and may result in stagnation in the development of the network and, potentially, a future shortfall in transmission capacity.

We set out our views on these issues below, and our response to the consultation questions in an annex to this letter.

The costs and benefits of the proposed options

The consultation paper and its Regulatory Impact Assessment do not provide cost-benefit analyses of the proposed exclusive and non-exclusive licensing options. Further, the paper does not provide cost-benefit analyses of those options that have been ruled out. Without such analysis, it is difficult to make a meaningful comparison of the options. We believe that it is critical that this analysis is undertaken before a final decision on the regulatory regime is made.

The Regulatory Impact Assessment (RIA) does provide an estimate of the potential costs associated with bidding under a non-exclusive licence approach and an exclusive licence approach. Table 1 of the RIA shows potential bidding costs under the non-exclusive licence approach may be in excess of £100 million for the three strategic areas of the North West, the Greater Wash and Thames Estuary. Table 2 of the RIA shows potential bidding costs of around £25 million for the allocation of licences for five exclusive areas. The consultation document suggests that bid costs could be paid for by the successful bidder as a condition of its licence. These costs would be recovered through use of system charges and, hence, ultimately paid for by the electricity consumer.

The consultation document suggests that, despite the higher costs associated with licence allocation, costs would be driven down by the competitive pressures of the bidding process. However, previous experience demonstrates that much of the cost associated with a large capital project of this type is in the initial asset procurement which is already fully competitive. Since competitive procurement is a legal requirement it would continue under whatever transmission licensing arrangements applied offshore. Given this, a requirement to comply with system design standards and the limited pool of equipment manufacturers it is likely that any offshore TO would have very similar upfront capital costs for a given scheme.

Potential savings could be realised in project management and network operation. However, experience again demonstrates that such savings are likely to be minor. The greater cost to the licensee will be the cost of financing, and the challenge to a competitive process would be to deliver a lower rate of return than the regulated rate of 4.4% (post-tax real). Even if this could be achieved then the potential savings are not great – a reduction in the cost of capital of 50 basis points on a total regulated asset base of £1.4 billion (based on the study of Round 2 projects undertaken by Econnect for the DTI) would be equivalent to a difference in the revenue allowance of around £3.5 million per annum (based on the average return on a declining asset base over the asset life).

Complexity and transparency

Both of the approaches set out in the consultation paper would require a competitive tendering process to determine the licensed transmission services provider. Clearly, establishing a licensing regime and the associated tendering process would take some time. This would further lengthen the uncertainty and delay for those developers working in the existing strategic areas. However, future developers would also experience delays in the appointment of a TO following their application for a grid connection. Under the proposed non-exclusive option, a tendering process would be required for each new application (regardless of whether that project proceeds to construction). Under the proposed exclusive approach, in the first instance the licensed area would be geographically restricted, hence future developments located outwith these areas would require a tendering process to determine the TO.

In addition to the delay in a TO being identified following the application for connection, the developer would be subject to an extremely complex application process. The GBSO would be required to contact all the parties involved, pay the application fee and consolidate the connection offers. The use of system charge that the offshore developer would be liable for is also likely to be unknown at the time of application and, indeed, would be unknown until some time after the offshore TO is allocated. The likely complexity in the connections process has been illustrated by the high-level process diagrams produced by NGET following the workshop on 29 November 2006.

The industry would also undergo a significant upheaval if either of the approaches proposed in the consultation paper was to be implemented. As acknowledged in the consultation paper, all of the existing industry codes, practices and governance procedures would require review. This includes the Grid Code, the SO-TO code, the CUSC and the BSC. There is a further issue identified with DNO interfaces and the potential for a ‘DNO sandwich’ between the offshore and onshore TO that is likely to require a new industry code.

It is true that some code and licensing changes will be required whatever approach is adopted for offshore transmission, however the introduction of a competitive tendering process and the resulting increase in transmission owners would add significantly to the scope and extent of changes required and the ongoing burden of complexity.

Co-ordinated, efficient development of the transmission system

Our final concern, and potentially the most important, is the issues that are raised with regards to the co-ordinated development and interoperability of the transmission network. We are particularly worried that these issues have not been explicitly identified and discussed in the consultation paper.

The onshore transmission system is owned and maintained by well established and focused TOs, governed by clear, well established industry codes and, as a result, the network functions well with co-ordinated system development and maintenance on a GB-scale. This well functioning onshore system could, in our opinion, be jeopardised by the implementation of the proposed exclusive or non-exclusive licensing options for offshore.

By introducing a larger number of network owner interfaces, it requires the GBSO to secure agreement from a larger number of parties either for economic, efficient and co-ordinated developments of the GB transmission system or for co-ordination of outages. All network owners need to agree. Experience in other countries, most notably the United States, has demonstrated that where network ownership is fragmented across disparate and varied parties then it becomes very difficult to co-ordinate system access both in the sense of new generation and demand entrants and for maintenance, and to agree appropriate reinforcements necessary to facilitate such new entrants. Ultimately, this can lead to stagnation and a shortfall in transmission capacity.

SSE has already expressed its view that extension of scope of the existing licences offshore is the approach most consistent with the co-ordinated and efficient development of the GB transmission system. Further, we believe that this approach is the most straightforward and deliverable of the options and therefore most likely to avoid cost, complexity and delays to the development of offshore renewables. We are disappointed that the consultation document has ruled out this option without due consideration of the costs and benefits of such an approach compared with those proposed.

I hope these comments are helpful, and if you would like to discuss this further then please give me a call.

Yours sincerely

Rob McDonald
Director of Regulation

2. Regulatory options

Chapter 2: Question 1

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

The two options proposed in the consultation document are (i) non-exclusive licensing, and (ii) exclusive licensing. Of these two options, SSE prefers the exclusive licensing option whereby a single TO would be exclusively responsible for a defined geographic area although, as we explain below, we do have some issues about the proposed "multi-zone" approach to the granting of exclusive licences.

Our reasons for preferring the exclusive option are simple – this option offers a clear and transparent regulatory regime that can be implemented quickly for minimum cost and with minimum disruption to existing industry codes, governance procedures and practice. As the consultation document points out in paragraph 2.45, from a generator's point of view an exclusive system would be identical to that onshore providing generators with the regulatory certainty that they require to proceed to financial close and construction.

The alternative option proposed in the consultation paper is non-exclusive licensing. Under this option, multiple non-exclusive licences would be granted and TOs selected on a site-by-site basis. This option is clearly complex with multiple elements to the proposed regime:

- Firstly, the issuing of licences to non-operational businesses;
- Secondly, the submission of a connection application from a generating station and the preparation of the tender process;
- Thirdly, the submission of bids from licensed TOs;
- Fourth, the judging of bids and allocation of the licence; and,
- Finally, the regulation of the operational TO.

This process would have to be undertaken for each generating station that submits an application for connection (regardless of whether the generator actually proceeds to construction).

We believe that the proposed non-exclusive licensing regime is overly complex and will deliver no tangible benefits, yet would come at significant cost. In addition to the actual financial costs associated with this option, we have significant concerns regarding the implications for operability, common access and co-ordinated development of the network. An inevitable consequence of this option would be the creation of multiple network owners. The GBSO would be required to, effectively, gain agreement from all of these owners to co-ordinate maintenance or development. Experience in other networks that are natural monopolies and in transmission networks overseas demonstrates that the larger the number of network owners, then the harder it becomes to co-ordinate common access and operate the system. Further, the future development and reinforcement of the transmission system is frustrated by multiple ownership interfaces leading to stagnation and, ultimately, a shortfall in transmission capacity.

In addition, there is risk that no licensed TO would come forward to tender to provide the connection for a generating station. In this circumstance, the generator would have little choice but to apply for its own licence and provide its own connection. Developers have in work groups and responses to previous consultations expressed a clear desire not to follow this route.

In summary, we believe that, under the exclusive option, a licensing regime can be put in place quickly and for lowest cost. The regime established would be simple, transparent, easy to understand and enduring. This would give certainty to developers of offshore generating technology both now and in the future. Further, issues of access and operability would be minimised, and future reinforcement and growth would be undertaken timeously and efficiently. However, as noted in our covering letter, we consider that a tendering exercise to allocate exclusive licences would introduce significant cost, new industry interfaces and significant additional complexity. As a consequence, in our view, a much simpler approach would involve extending the scope of the existing transmission licences offshore.

Do you have any views on any aspect of our intended approach under each option?

Although we prefer the exclusive option, we have some concerns regarding the proposed “multi-zone” approach to implementing this option. The “multi-zone” approach would see a number of regional monopoly TO areas established and the licence for each area awarded by means of a competitive process.

The benefits of the exclusive licensing option include its simplicity, low cost and potential to endure. These benefits have been demonstrated by the broadly equivalent onshore regime. Onshore, when a new generating station applies for a connection to the main interconnected transmission system the TO is known and the GBSO can make an offer to the developer within 28 days. This process is transparent and easy to understand by all parties involved.

Under the “multi-zone” approach many of the benefits of the exclusive licensing option would be lost. In particular, this would introduce significant costs through the licensing process, result in delay in the provision of a transmission connection, add complexity to the access to and operation of the transmission network, necessitate changes to established industry codes, practices and governance procedures, and potentially inhibit the interoperability and development of the network. Consequently, we continue to believe that the straightforward extension of the existing transmission licensed areas is the best approach to the exclusive option.

Chapter 2: Question 2

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

Yes. We continue to believe that the exclusive licensing approach of extending the scope of the current TO licences into the offshore is the most pragmatic approach to offshore transmission. This approach, in our view, would result in a clear, simple and transparent regime that could be implemented quickly at little cost to the industry. The regime could be implemented with minimal disruption to existing industry codes, governance procedures and practices, and give certainty both to existing participants and future participants.

The consultation paper explains that the "extension" approach has been ruled out because of the inequitable distribution of the size of each area, and because it would not require the TO licensees to demonstrate their suitability or financial commitment. We do not believe that these reasons, if valid, are sufficient grounds to rule out this approach. The "extension" approach has been ruled out without, in our view, due consideration of the loss of benefits and the costs of alternative approaches. In particular, we note:

- Customers already benefit from the competitive procurement of assets with additional regulatory oversight of the efficiency and economy of costs at each price control review.
- The additional risks involved and the loss of the portfolio effect will contribute to higher financing costs for the new entrant.
- The development, implementation and management of a new regime will always cost more than extending an existing regime.
- Extension would require minimum changes to the industry codes, practices and governance procedures.

Further, we believe that the view of the generating industry (as expressed in response to previous consultations and at working groups) is for a simple, quick to implement and cheap solution, and the consultation acknowledges that the "extension" approach is "the simplest and easiest way".

Chapter 2: Question 3

Should anything further have been taken into account when assessing the options?

Yes. There is a clear need for a cost-benefit analysis to inform this consultation document. In some respects, without such an analysis, it is difficult to come to an informed view about the preferred licensing regime.

The Regulatory Impact Assessment (RIA) provides some information in relation to the costs and benefits of the two preferred approaches; however no analysis of the approaches that have been ruled out is provided and the information that is provided has largely not been quantified. In addition, the analysis in the RIA is not referred to in the main consultation document and, in many cases, the two contradict each other. For example, under the non-exclusive licensing option, the main consultation document notes several times that this option would result in early delivery of offshore transmission. In contrast, the RIA describes the likelihood of delays under this option as a result of factors including the lengthy application process, complex bid evaluation and potentially no TO coming forward.

Ultimately, what is of concern to the customer is what each regime would deliver and at what cost. The 2005 consultation document ‘Regulation of offshore electricity transmission’ provided helpful annexes on illustrative TNUoS charges and capital costs. Equivalent annexes would be of use to support this consultation.

3. Practical issues under the regulatory options

Chapter 3: 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?

Yes.

The concerns of the Round 2 developers are understandable given the status of their projects and the continuing uncertainty surrounding the provision of a grid connection. Such uncertainty extends not only to the “legal issue” and “price issue” with respect to the identity of the transmission owner and asset adoption, but also to the conditions of connection including use of system charges and access rights. Given such uncertainties, it is understandable that these developers are seeking further comfort from Ofgem. Indeed, it is not difficult to foresee circumstances where, without such comfort, they may have no choice but to defer their projects in the face of continuing regulatory uncertainty.

The deferment of Round 2 offshore wind developments is not consistent with Government policy and targets (as set out in Annex 2 to the consultation). Hence we agree that Ofgem should consider providing greater certainty to projects that will be constructed or attain financial closure prior to the award of offshore TO licences. One option would be to ensure that these developers will have a right under the licensing regime to request adoption and a guarantee that as part of this right assets will be adopted "at efficient cost". However, in these circumstances, it will also be necessary to provide prospective TOs with comfort about the recovery of costs involved in adopting these assets. If this is not forthcoming then potential bidders for licences may be discouraged.

The licensing options proposed in the consultation document are extremely complex and, if implemented, would take significant time to put in place. This will further lengthen the delay for Round 2 developers. The continuation of the existing uncertainty during this time is neither acceptable nor desirable to the developers concerned and to the wider UK renewables industry.

Chapter 3: Question 2

Would a departure from Ofgem's current approach to the adoption of assets be justified or would different treatment be unduly discriminatory?

Yes – a departure from Ofgem's current approach to the adoption of assets would be justified; and, No – different treatment would not be unduly discriminatory.

The Round 2 offshore wind developments are, as described above, in an unique set of circumstances and it is unlikely that other developments would require the same comfort. Given this, it is reasonable that further comfort is provided to the Round 2 projects without this setting a regulatory precedent or showing undue discrimination. These projects have proceeded in good faith that a regulated transmission owner would be in place by the time of financial close – as was stated at the launch of Round 2 in 2003 by the Secretary of State. It is unfortunate that, while the generating stations are now in a position to proceed to construction, the development of the offshore regulatory regime has not concluded.

Chapter 3: 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 minimised?

The costs and complexity of the tendering process under the proposed non-exclusive licensing option are issues of significant concern. We have similar concerns regarding the tendering process under the proposed exclusive licensing option and consider these later in our response. In terms of costs unique to the proposed non-exclusive licensing approach, during the tendering process for each generation station the party managing and assessing the bids will incur costs and all of the potential bidders will incur costs. However, regardless of when costs are incurred in the process and by whom, it is the end consumer of the electricity that will pay.

It is critical, in our view, that before a decision on the regulatory regime is made a detailed cost-benefit analysis of each of the proposed approaches is undertaken. Indeed, we are extremely disappointed that such an analysis has not been undertaken to inform this consultation. Cost-benefit analysis is particularly important when one approach is presented as the preferred approach. Clearly, and as demonstrated in the Regulatory Impact Assessment, there would be significant costs associated with setting up and managing the tendering process and the cost of bidding for a non-exclusive TO licence. Such costs would have to be offset by competitive pressures driving down the construction and operating costs of the successful bidder in order for the benefits of this approach to outweigh the costs. That the benefits of the non-exclusive option outweigh the costs has not been demonstrated in the consultation paper.

If we consider in more detail the costs of the non-exclusive option, there are two key components:

- Firstly, there are the costs associated with establishing, managing and operating the licence issuing and subsequent tendering and assessment process; and
- Secondly, there are the costs to the potential TOs of acquiring a licence and then preparing and submitting a bid(s).

Note that this takes no account of the additional upfront costs to the industry of modifying existing codes and practices, and the cost to the generator associated with the uncertainty and additional risk of an unknown TO; again the costs of these are likely to be significant.

The consultation document proposes a number of mechanisms that may reduce the potential costs of the tendering and bidding process under a non-exclusive licensing regime. For example, that the GBSO (or another party) could be required to undertake preliminary works and/or the successful bidder could pay for all bidders' costs. While such mechanisms may result in a reduction in costs, they contribute further to a process that, as proposed, is already extremely complex. In addition, the mechanisms suggested while solving one problem, in many respects, only create others. For example, who would judge if the preliminary works were undertaken in an economic and efficient manner? How would the bid costs of unsuccessful bidders be measured and that cost passed on the successful bidder? It also raises the concern that such complexity may put parties off bidding altogether.

The Regulatory Impact Assessment suggests that the potential costs involved in bidding under the non-exclusive option could be £50 million for the Greater Wash strategic area alone and in excess of £100 million for all three strategic areas. In terms of an equivalent revenue allowance, based on a 20-year depreciation period and 6.25% cost of capital, the bidding costs alone could exceed £8 million per annum which would have to be recovered from use of system charges. For this option to be credible, and assuming that these potential bidding costs are accurate, then the bidding costs should be exceeded by the savings in construction and operating costs of the successful bidder compared with all other possible approaches.

Experience of large capital projects of this type demonstrates that the majority of costs are associated with procurement of assets which is already fully competitive. Since competitive procurement is a legal requirement it would continue under whatever transmission licensing arrangements applied offshore. Given this, a requirement to comply with system design standards and the limited pool of equipment manufacturers it is likely that any offshore TO would have very similar upfront capital costs for a given scheme.Consequently, the variance in bids is likely to relate to project management, operating and financing costs. It is not clear that savings in these areas are sufficient to offset the high costs associated with the bidding process.

The most significant of these three components is the financing costs. A difference in the cost of capital of 50 basis points on a total regulated asset base of £1.4 billion (based on the study of Round 2 projects undertaken by Econnect for the DTI) would be equivalent to a difference in the revenue allowance of around £3.5 million per annum (based on the average return on a declining asset base over the asset life). The cost of capital allowed in the most recent transmission price control is 4.4% (post-tax real); hence a difference of 50 basis points would be a reduction in excess of 10% on the regulated rate. It is also clear that potential bidders in a competitive framework would require higher, not lower, returns than a regulated monopoly. Again, we would urge Ofgem and the DTI to undertake a thorough cost-benefit analysis before making a decision on which licensing option to pursue.

Chapter 3: 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?

Yes. We agree that a lack of co-ordination is a significant risk under the non-exclusive licensing option. However, we believe that this is an issue not specific to the non-exclusive option, but is also a risk under the proposed “multi-zone” approach to the exclusive licensing option.

Consider, for example, if the system operator determined that two areas under an exclusive licence – the North Wash and South Wash, say – should be linked for reasons of efficient power flow management. Similarly, if preliminary works demonstrated that the most efficient grid connection for the Greater Gabbard development involved a link to the London Array which was already licensed under the non-exclusive approach. In both instances, the existing offshore TO would view these variations to its original tender as outwith the scope of its licence and, most likely, look to reopen its regulatory settlement resulting in significant time and cost implications. The alternative would be the development of an inefficient alternative capital solution or a loss of system interoperability.

A lack of co-ordination is, essentially, a consequence of multiple network owners between the generating station and the demand load. For economic, efficient and co-ordinated system operation and development, all network owners need to agree. Experience in other countries, most notably the United States, has demonstrated that where the network ownership is fragmented across disparate and varied parties then it becomes very difficult to co-ordinate system access both in the sense of new generation and demand entrants and for maintenanc, and to agree appropriate reinforcements necessary to facilitate such new entrants. Ultimately, this can lead to stagnation and a shortfall in transmission capacity. This problem is not unique to the electricity transmission network, but is common to network businesses; for example, the subsea pipeline infrastructure in the North Sea and Irish Sea.

In our view, issues of network interoperability and common access should be approached with caution, the implications for future network growth acknowledged and such an approach only pursued where the known benefits are compelling. The onshore transmission system is owned and maintained by well established and focused TOs, governed by clear, well established industry codes and, as a result, the network functions well with co-ordinated system development and maintenance on a GB-scale. This well functioning onshore system could, in our opinion, be jeopardised by the implementation of the proposed non-exclusive licensing option.

The consultation document puts forward a number of possible mechanisms to mitigate the risk for inefficient expenditure and poorly co-ordinated development under the non-exclusive approach. All of the proposed options relate to the initial tendering process and not to a licensee's obligations with regard to the operation, access and future development of the network. We are extremely concerned that the options proposed in the consultation document do not address these very real issues.

The mechanisms proposed to address co-ordination during the tendering process include application 'windows', multi-scheme bidding and conditional bids. Again, while these mechanisms may address the specific issue of inefficient capital investment, they add further complexity to a process that, as proposed, is already extremely complex. It can also be argued that while possibly solving one problem these mechanisms are only creating another.

For example, one particular mechanism proposed, that of 'application windows' has a particular precedent with the December 2004 closure for Scottish applicants ahead of BETTA implementation. By setting a timeframe for connection applications from offshore generating stations, and given that grid capacity is allocated on a "first come, first served" basis, this creates an artificial deadline for onshore developers to, in effect, get ahead of the offshore developers in the GB queue. To avoid an avalanche of applications similar to that which occurred in late 2004 would require further 'fixing' mechanisms, and so on.

In addition, it is not clear how mechanisms suggested to address this issue will interact with mechanisms proposed elsewhere in this document to address other issues. For example, if the successful bidder is required to pay for the economic and efficient costs of unsuccessful bids (as proposed elsewhere) how will costs be split when a bidder has made multiple bids not all of which have been successful? Again, there is a risk that this uncertainty would discourage bidders altogether.

Chapter 3: 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?

The option that the owner of an offshore generating station could build, own and operate its connection to the onshore grid is clearly necessary given the continuing uncertainty surrounding the offshore licensing regime and the progress of Round 2 offshore wind projects towards financial closure and construction. Further, under the approaches proposed in the consultation document, the possibility remains that no party will submit a successful bid to provide the connection and the owner of an offshore generating station will have no choice but to provide its own transmission services to shore.

However, if the owner of an offshore generating station did build such a transmission line (or lines) to connect to the onshore grid, then there may be an issue with business separation requiring, at the very least, a separate legal entity to be the licensee to own and operate the line(s).

Chapter 3: 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 ensure this?

Clearly, under the proposed non-exclusive licensing approach, it will be necessary to ensure appropriate business separation of NGET's SO and TO functions. The issue of NGET as SO and TO is less of a concern under the proposed exclusive licensing approach.

Chapter 3: Question 7

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

It is the nature of all contracts that some elements of the agreement are "fixed" and others subject to renegotiation in given circumstances; the "nature of the firmness" varies between contracts. This is the case in pure commercial, competitively procured, agreements and, at the other end of the competitive spectrum, price controlled regulatory settlements. If reopeners are not to be allowed, then the bidders will clearly factor this risk into the price that is bid for the licence. Depending on the information that is available, this could clearly lead to bidders including very large contingency allowances to mitigate the uncertainties in the project. This could lead to revenue allowances being set which exceed the actual project costs, which would be inefficient.

In our view, there would need to be some scope for reopeners. The nature of these reopeners will be a function of the regime chosen and the form of the price control. We agree that it is important to identify those circumstances where a regulatory settlement may be reopened before a regime is put in place. This should be an important part of the determination process and form an essential component of the cost-benefit analysis.

Chapter 3: Question 8

How should the geographic extent of exclusive regional licence areas be defined?

We have commented earlier on the issue of co-ordination and interoperability of the GB transmission system. This issue we believe is critical to the success, or otherwise, of the bulk transfer of electricity particularly given the widening portfolio of generators (including renewables) and their location with respect to demand load. On this basis, we continue to believe that the geographic extent of exclusive regional licence areas should be consistent with extension of the existing onshore transmission ownership boundaries.

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?

Licensed electricity network operators have an obligation to offer terms for connection. During the price control process, this obligation is acknowledged and the efficient capital and operating cost of providing a connection is funded through additions to the RAV. Clearly, the number, size and location of generators that could ask for a connection to the grid in any network operator's area are unknown. In extreme circumstances, a large number of generators could apply for connection resulting in financial pressures to fund the upfront capital investment required. This point is as valid onshore as it is offshore as demonstrated by the recent demand for connections from renewable developments in the north of Scotland.

The consultation document suggests that, in order to avoid the financial pressures associated with investing in connection assets, the size of the offshore licensed area is minimised. Such an approach would not be consistent with the onshore licensing regime and, at its extreme, would result in one licensed area per generating station. This would result in the operational and development difficulties associated with multiple network owners between the generating station and demand load. We believe ensuring the future co-ordinated development of the transmission system is of critical importance when putting this new regime in place. The assessment of availability of financial resources should form an important part of the selection process as described below. Hence issues related to financial pressures should be addressed at that time rather than through artificially restricting the licensed area.

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 decision is made not to extend the onshore transmission ownership boundaries, then we agree that it would be appropriate to limit coverage of three, or more, licences to the three strategic areas. There may be further scope for subdivision of the Wash and Irish Sea areas into northern and southern licensed subareas.

Chapter 3: Question 9

On what basis should the competition for offshore exclusive TO licences be run?

Given that an exclusive transmission licence, once issued, would remain with the successful bidder for at least the life of the regulated assets, it is important that the process for selecting the licensee is thorough and rigorous. Further, to build the necessary confidence in the licensing regime, the process should be open and transparent.

The consultation document suggests that one possibility for assessing applicants is a combination of credit worthiness and relevant experience. We agree that applicants must be assessed against these criteria; however we believe that these two criteria alone are not sufficient. In our view, the process must include an assessment of the applicant's technical suitability in the provision of transmission services and further must ensure that the applicant has adequate resources (including financial, assets and managerial resources) to undertake the regulated business. In essence, the successful applicant must be able to comply with the conditions of the transmission licence both in the short and long term, and provide a value for money service that benefits consumers.

A common model used to assess potential technical joint venture partners is a Request for Proposals (RfP). Under this model, applicants receive a design brief and are required to submit designs and proposals including detailed technical specifications, method and approaches to be used and initial costings. A similar approach could be employed in the selection of offshore licensees with a design brief based, in the first instance, on known schemes in the licence area and a number of prospective future schemes including the extension and further development of the known schemes. A RfP could be required in addition to a document explaining the applicant's proposals for licence compliance.

Chapter 3: 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 and analysis of the expenditure of the regulated business is an essential component of the model for regulating utilities in the UK. Such analysis and regulatory oversight is necessary given the absence of competitive pressures. However, if the Government proceed with either of the proposed competitive tendering processes presumably there would be no need for further regulation (since competitive pressure in the bidding process is cited as a key benefit of the regime).

This point notwithstanding, the consultation document notes that different conditions in different geographic areas might make comparative analysis difficult. This may be true, however the differences offshore are likely to be less than the differences between the onshore TOs which are very different in size, asset base, customer base and location. If regulatory analytical and monitoring techniques can be established for the onshore TOs, then such techniques can also be established for the offshore TOs.

In particular, we believe that there may be significant scope for process benchmarking; for example, jacket installation, pipe/cable laying. The hydrocarbons industry has been established for over 30 years in the North Sea and Irish Sea, and many of the capital works required for an offshore wind installation are as required for offshore oil and gas operations. This information could be used to inform the tendering process and subsequent regulatory analysis and monitoring.

The consultation paper proposes that in order to ensure a single party does not win all the available licences (hence removing the scope for comparative analysis), licences could be awarded on a preference basis. This proposed mechanism, while potentially addressing the identified problem, would appear to only create further problems – not least how to ensure the most economic and efficient investment in the transmission network. This further 'fixing' mechanism would result in the overall regime becoming more complex and difficult to understand; hence, more costly and taking longer to implement.

With regards to the specific proposal for licence allocation on a preference basis, this is clearly not in the best interests of customers. The purpose of inviting applicants for the licence is surely to identify that the best party to provide the service. Allocation on a preference basis undermines this purpose.

Chapter 3: 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?

Under a price control, the setting of the RAV and the allowed cost of capital are critical. The addition of assets to the RAV reflects the economic and efficient value of that investment. The cost of capital is set at such a level to attract the required investment and ensure that the regulated business has sufficient earnings to finance its functions. We believe that these well established principles should be retained in the price control for offshore TOs.

The issue of setting a price control for an offshore TO is clearly one which requires a great deal of work which will be dependant upon the outcome of this consultation. We support the principle set out by the price control subgroup that the price control framework for the onshore network businesses should form the starting point for this work. An incentive-based price control approach remains, in our opinion, the most appropriate form of price control rather than rate of return regulation.

Would it be suitable to use international benchmarks as a means of assessing economy and efficiency?

We comment on the use of benchmarks above. The use of international benchmarks in utility regulation has proven to be extremely difficult given differences in, for example, accounting standards, operational practices and standards, and exchange rates. Consequently, such comparative analysis should be approached with caution. However, as we describe above, we believe that sufficient data may exist to allow benchmarking with other offshore assets.

<u>Chapter 3: Question 12</u>

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

The licensing regime that is put in place needs to be enduring and hence capable of dealing with offshore generators sited outwith areas with a licensed TO. We note that concerns relating to future build would not be an issue under the exclusive option of extending the existing licensees' areas.

However, if the entire offshore area is not to be licensed at the outset, then a pragmatic and proportionate approach needs to be taken. For example, it would clearly not be sensible to create a new licensed area and initiate a complex tendering process for a single windfarm located geographically and electrically proximate to existing offshore generating stations but sited, by a matter of metres, outwith an existing licensed area. A test of "reasonableness" could be included in the transmission licence to prepare for such an eventuality.

This issue is not one that will arise overnight. The Crown Estate and the DTI will, in time, make a decision regarding the further development of the strategic areas or make available seabed in other areas. Such decisions and the subsequent tendering for leases will give sufficient time for the Authority to consider the implications for the transmission licensing regime. Indeed, if further strategic areas are identified, it is possible that the tendering for the TO under the exclusive option could take place at the same time as the tendering for leases.

We have commented earlier on the interoperability of the transmission network and the potential consequences of network fragmentation such as a shortfall of transmission capacity. This issue is of particular concern if pragmatic and timely decisions are not taken to deal with generating stations located outwith licensed areas. For example, if the regime adopted is “multi-zone” exclusive licensing yet future geographically isolated projects are dealt with on a stand-alone basis then the benefits of the exclusive licensing approach would quickly be lost.

<u>Chapter 3: Question 13</u>

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

Under the heading ‘Encouraging efficiency in timing’, the consultation document explains that in order to implement the proposed “multi-zone” approach to the exclusive licensing option the Authority would be required to make regulations that allow the granting of a licence as a result of the tender process. This, it is suggested in the consultation document, will significantly lengthen the time before an offshore TO licence can be granted.

We agree that the proposed “multi-zone” approach to the exclusive licensing option will result in a significant delay before a licensee is place. However, this is also the case for the proposed non-exclusive licensing option (although this is not examined in the consultation document). Again the Authority will be required to make regulations that allow the granting of a licence as a result of the tender process. Under the exclusive licensing option, the Authority will only need to undertake the tendering process once whereas under the non-exclusive licensing option the Authority (or a third party) will need to undertake the tendering process for every connection application. It is clear that the time associated with determining an offshore TO is likely to be even longer under the non-exclusive option than the exclusive option.

The consultation document goes on to consider how the connection application process will work given this uncertainty around the offshore TO and its obligations at the time the application is made. Again we believe that this issue is as significant, indeed possibly more significant, under the non-exclusive licensing option. The potential complexity of connection application process under both the proposed approaches has been illustrated by the high-level process diagrams produced by NGET following the workshop on 29 November 2006. It is clear that the existing applications process would not be adequate if either of the proposed approaches was adopted, and that the existing 28-days for providing a developer with an offer would need to be significantly extended.

The points raised under this question provide a good illustration of our concerns with regards to the proposed approaches. The length of time to put in place an offshore TO is one of the key reasons that SSE continues to support the extension of the existing licensed areas. Further the implications of the proposed approaches to well established industry processes, codes and practices, in this instance the connections process, should not be underestimated. We believe that these issues need to be examined more thoroughly and a comprehensive cost-benefit analysis undertaken before a decision on the regulatory regime is taken.