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E.ON UK response to material issues in the joint Ofgem / BERR regulatory policy update on Offshore Electricity Transmission

Dear Sam, Paul,

E.ON UK welcomes this opportunity to respond to the joint Ofgem / BERR regulatory policy update on offshore electricity transmission, published on 13th June 2008. E.ON is the developer behind the Robin Rigg and Humber Gateway offshore windfarms. We are also a joint shareholder in the London Array project and have significant aspirations towards future offshore generation in Round 3. Our response follows on from our response on material issues dated 4th July 2008. We respond to each of the questions in the policy update in turn below:

__Chapter 2__ **- we would welcome views on the following issues:**

Revenue adjustments - should the regulated revenue stream be adjusted and, if so, how should this be designed?

We continue to be of the view that adjustments to the revenue stream should be in limited defined circumstances, as this would otherwise undermine the firmness of bids and in turn the competitive tender process. Adjustment on certain pre-defined costs allows for a degree of certainty to mitigate against exceptional claims from OFTO's for revenue adjustments.

The ability for the OFTO to pass through unreasonable or uncompetitive costs should be managed, as this may have implications for the volatility of the offshore generator's charges, and we therefore agree that the criteria for pre-defined adjustment mechanisms should be subject to materiality. We would support pre-defined, using RPI, indexation against O&M and insurance costs.

We agree that pre-defined adjustment mechanisms should not relate to capital expenditure to provide the offshore transmission assets. Ofgem will, however, need to take in to account the ability of the OFTO to improve on the firmness of its price as the bid is refined through the tender process.

Incremental capacity – what are your views on our updated position?

We support Ofgem's updated position.

An alternative approach may be needed for Round 3 offshore generation development. As a number of different wind farms could comprise a Round 3 zone, these windfarms may come forward in different timescales. The most economic and efficient offshore transmission solution in the longer term may, however, be to provide an offshore network that can accommodate a larger amount of generation than initially applies.

In these circumstances Ofgem could treat the offshore transmission investment in a similar fashion to strategic network upgrades that is being considered under the Transmission Access Review for onshore investment, with a range of rates of return being available to an OFTO based on utilisation. This would allow an OFTO to invest ahead of user commitment, whilst ensuring that the most economic and efficient network is available in a timely manner for increased generation capacity, over and above the present 20% incremental threshold.

What are your views on the appropriate structure and level of OFTO performance incentives; including how much of the regulated revenue stream should be exposed to such incentives?

We support the asymmetric OFTO performance incentives on capacity delivery and operational availability to influence OFTO behaviour. Whilst we support the base levels of availability and degree of annual regulated revenue exposed, the level of incentive could be a matter that is negotiated through the tender process, or in response to a generator request for different levels.

The base level of incentive should not, however, materially increase the risk level of the OFTO opportunity, with the upward effect this would have on the cost of capital. This would flow through to the generator's use of system charges and in effect be a form of self insurance by the generator, as it would effectively pay for the incentive as the OFTO would price this component in to its bid.

During pre-construction and construction activity it may be appropriate to log the level of OFTO revenue adjustment under a capacity delivery incentive and adjust it at the point the offshore network is completed. This would then flow through to the generators charges once it connects. In contrast, revenue adjustments under an operational availability incentive should be adjusted annually so that the generator can see the benefit in the subsequent year, either through reduced charges or as a direct payment to the generator, up to the level allowed in the OFTO's incentive, via the GBSO.

What should be the role of the generator in defining the level and structure of performance incentives ex ante as part of their requirements?

We would welcome the ability for the generator to comment on the acceptability of the levels of the incentive arrangements to apply to the OFTO. However, to the extent that incentive arrangements are intended to promote certain behaviours, should the level of incentive not be sufficient in practice, the generator should be able to separately contract with the OFTO to share additional costs that may be incurred to undertake certain construction or operation and maintenance activities, such as acceleration costs associated with cable repair. A generator may be prepared to share a proportion of these costs as its loss from an OFTO's failure to perform or limited ability to resolve repairs will be far greater to the generators business than the OFTO.

We look forward to considering Ofgem's proposals on the potential arrangements to mitigate against the risk of major outages during the life of the asset.

What actions should be taken in the event of persistent OFTO underperformance?

The Authority would have a number of different mechanisms available to it to remedy persistent OFTO underperformance. This might range from an initial enforcement warning, through to fines and ultimately revocation of the licence.

Should revocation of the licence be necessary, Ofgem must ensure that there is a third party available and willing to undertake the offshore transmission licence activities, to honour existing contractual arrangements, during the interim period to prevent disruption to the generator, either to its connection date or continued operation. This may then allow for the specific licence to be re-tendered to appoint a new party that meets the OFTO pre-qualification criteria. The length of notice given to the incumbent OFTO that its licence is to be revoked will need to factor in the time needed to resolve these issues.

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<u>Chapter 3</u> - We would particularly welcome views on the following:

The proposed pre-conditions for the enduring tender process, and in particular whether there are any other pre-conditions that it would be appropriate to consider.

We support the proposed pre-conditions for the enduring tender process and welcome the practical approach Ofgem is trying to take on timing of acceptance of the NGET CUSC connection offer and at what point the project is tendered, depending on likely connection timescales.

We would highlight that, depending on the timing of the tender window, by requiring the NGET CUSC connection offer to be accepted that this will take approximately six months from the original application being submitted to NGET, whilst the EOI stage of the tender process could potentially commence in parallel.

Perhaps greater emphasis could be placed on the second pre-condition, with the developer having entered in to suitable lease arrangements with the Crown Estate. If the EOI stage is to commence prior to issue or acceptance of the NGET CUSC connection offer, then the amount of project specific information provided by Ofgem under the EOI needs to take in to consideration confidentiality requirements, to avoid any implications to the offshore developer securing transmission capacity, in particular when competing with onshore projects.

The proposed approach for treating seabed surveys in the enduring regime.

We welcome the option for the developer to continue to progress design and consenting of the offshore transmission cable routes. There is however a risk that the route progressed by the developer may differ from potential proposals by the OFTO bidders. Where the successful bidder's design and cable route differs to that of the developer's then in this instance the developer must be able to recover the costs of its unutilised development work made available in the data room, providing the costs have been efficiently incurred.

The cost of seabed surveys for the bidder's design could be progressed during the tender process itself, which would allow the bidder to firm up its bid as the tender process progressed towards selection. If the offshore developer undertakes the seabed survey and makes this information available in the data room, as before there is a risk that the bidder's carry out their own survey based on a different route. Again the offshore developer's costs of a seabed survey for an unutilised design should be recoverable, providing the cost has been efficiently incurred.

The proposed linkage between the tender process and the connection process.

We support the tender process and connection process and interaction between the two as presently defined and have no additional comments to make at this time.

The proposed approach for the OFTOs to provide construction security.

Whilst there is a need for an OFTO to provide some guarantee of financial capability to construct the offshore transmission assets, it is not clear how the money would be subsequently treated and used in the event that the OFTO was not able to complete construction. For instance, if the money was used to fund the uncompleted works, then presumably this element should not be charged to the generator or paid to any replacement OFTO, as it has already been funded by the defaulting OFTO.

The proposed approach that the preferred bidder will make its offer of construction through the normal STC process.

We support using existing code related processes that apply onshore to the offshore transmission regime in this regard.

Additional comments on the transitional tender arrangements:

Transitional criteria

Please note that those transitional projects that are currently licence exempt embedded medium power stations do not have, and are not required to have, an onshore connection offer from NGET.

We welcome the announcement by Ofgem at the offshore transmission communication session on 7th July that it will review the treatment of (existing transitional) licence exempt embedded medium power stations under the regime.

OFTO of last resort

We note the comments in the policy update stating that where an OFTO licence has not been appointed through a successful tender that the last resort mechanism will be considered on a case by case basis. We would appreciate further clarity on how Ofgem intends to apply the OFTO of last resort arrangements where the generation developer company has not established a separate OFTO business as a legal entity.

Should the competitive tender process not appoint a third party OFTO, how will the OFTO of last resort arrangements apply? Is it intended to impose on a generation developer the requirement to establish a new company, even though it may not want to, with the associated ring fencing and business separation requirements? If this is the case, we would welcome clarity under what legal power this requirement will be introduced?

If the separate legal entity is necessary, with associated ring fencing and business separation, sufficient time will be needed to establish the new business to meet the requirements. For those operational transitional projects in the April 2009 tender round an offshore transmission licence must be awarded in time for Go Live, to ensure compliance with UK legislation. In this regard the OFTO of last resort mechanism for individual transitional projects needs to be clarified and commenced in sufficient time for suitable and acceptable contingency arrangements to be in place for Go Live. This is in order to avoid the unacceptable situation that leads to the cessation of the export of generation until appropriate and acceptable licensing arrangements are put in place.

__Chapter 5__

Does the licence drafting reflect our policy positions?

As the new section E of the transmission licence replicates existing licence conditions we have no specific comments to make on the licence drafting. On a project by project basis as an offshore generation developer we will be interested in the special licence conditions that are created to address project and bid specific issues.

With regard to the additional transmission obligations that Ofgem is considering, we support Ofgem's intentions to create additional drafting to cover the SYS information, connection offers, performance incentives, overlay of licence areas and the relationship between NGET and any of its OFTO subsidiaries.

Are there any other issues that should be addressed through the licence changes?

We have no additional comments to make at this time, however we reserve the right to provide additional comments on the licence drafting as part of future consultations on offshore transmission licensing.

Chapter 6

Does the drafting in the annexed codes accurately reflect the policy positions set out in this document?

Please see our comments on codes drafting in the attached appendices. Our comments are limited to the CUSC and SQSS at this time. We have no comments on the Grid Code and believe that the drafting reflects the work of the Grid Code working group. We also support the drafting in section K of the STC. We, however, reserve the right to provide additional comments on the codes drafting as part of future consultations on offshore transmission licensing.

Chapter 7 - We seek views on our proposals that:

The mechanism for compensation arrangements for offshore generators should be defined in the CUSC.

We support the inclusion of the mechanism for compensation arrangements for offshore generators within the CUSC and the principles for an offshore generator's entitlement to compensation set out in the policy update. We look forward to commenting on detailed proposals in forthcoming consultations.

Revenue adjustments under an operational availability incentive should be adjusted annually so that the generator can see the benefit in the subsequent year, either through reduced charges or as a direct payment to the generator, up to the level allowed in the OFTO's incentive, via the GBSO. It is important that the offshore generator that is directly affected by the level of OFTO performance receives the full benefit of any compensation payments.

The mechanism for the OFTO funding of any compensation payable in respect of the availability of the offshore transmission system, to the offshore generator should be set out in the STC.

We support the inclusion of the mechanism for funding of any compensation arrangements from the OFTO to offshore generators to be set out in the STC. We look forward to commenting on detailed proposals in forthcoming consultations.

The performance incentive (performance targets and penalty payments) should

be set out in the offshore electricity transmission licence.

We support the OFTO availability performance incentive arrangements being set out in the offshore electricity transmission licence. We look forward to commenting on detailed proposals in forthcoming consultations.

We look forward to continuing to work with Ofgem / BERR on the successful implementation of the offshore transmission regime. We hope you find our comments helpful and we are happy to discuss them with you further should you wish to.

Yours sincerely

Guy Phillips
Senior Project Developer

Appendix 1 – Comments on the CUSC drafting

- In definition of Relevant Transmission Owner shouldn't it say "and any **Offshore Transmission Licensee** appointed in respect of a User's **Offshore Grid Entry Point/s**" or something similar. At the moment the definition applies to any Offshore Transmission Licensee which is too general. It should only be the licensee appointed in respect of the generator's connection. For instance, in 2.17 of the construction agreement the User is required to enter into a Interface Agreement with the Relevant Transmission Licensee.

- Para 2 on front of Interface Agreement (p222) says "Certain assets of the User are to be installed on the Offshore Platform title to which is vested in RTL and this Agreement is entered into by the Parties to give effect to appropriate arrangements in respect of such assets and also the use of certain facilities provided by RTL." Does this mean that the interface agreement is only used when the Relevant Transmission Owner owns the platform? What if the User owns it? For instance, elsewhere (such as para 2.5b of the Construction Agreement) provision is made for circumstances where the User owns the platform so it must be a possibility anticipated in the code.

- In 8.4 and 8.5 of the construction agreement different termination provisions exist for the provision of Facilities and Services dependent on whether they are included in Parts One or Two of Schedules 4 and 5 respectively. Those provided under Part One of either Schedule 4 or 5 can be terminated by the RTL with one year's notice. Those provided under Part Two of the two schedules can be terminated by both parties with 6 months' notice. However, there is no description of the difference between the two categories of service/facility and why the termination provisions differ.

- Para 12.4 of the draft BCA introduces an ability for automatic changes to be made to appendices F1 to F5 by National Grid. F1 to F5 are appendices from the existing standard form of BCA which relates to onshore. It is inappropriate to change the standard form of the onshore BCA using the offshore implementation process rather than the code amendment process.

- Para 1.2 (p301) of the Construction Agreement should have ")]" inserted after "fulfilled".

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- Para 1.2.2 (p301/2) doesn't seem to read correctly.

- Para 1.2.3 of Construction Agreement gives the Company "absolute discretion" to alter the document to reflect the Offshore TO Construction Offer. This is too wide a power to give the company. The words "The Company in its absolute discretion requires" should be replaced with "The Company reasonably requires".

- Para 1.3.4 of the Construction Agreement allows the agreement to be terminated if the tender which is operated by Ofgem is not carried out in the timescale prescribed in the Construction Agreement. However, the timescales would be determined by Ofgem. Therefore, how can National Grid set a deadline for it to be achieved in the Construction Agreement? Instead the Construction Agreement should reflect the timescales laid down by Ofgem. If this overruns, then the agreement should be varied to reflect this, not terminated.

- Paras 2.5, 2.6, 4.8, 11.1 all require assets to be removed from platforms within 6 months. Is this realistic on an offshore platform?

- Para 15.3 refers to 2.19, but there is no 2.19.

- In appendix O, what is meant by "size of turbines" when the capacity in MW is also asked for? Is this list of information the definitive list of information required?

- Appendix P contains the Offshore Works Assumptions. Again, is this the definitive list of information required?

Appendix 2 – Comments on the GB Security and Quality of Supply Standard (Annex 8)

Section 1 Introduction

General

There are quite a lot of section and paragraph references missing in the text.

We would welcome a review of terms and definitions to improve consistency between the industry codes and standards.

Clause 1.16

Can offshore platforms be owned by the Generator? – in which case these may not be part of the offshore transmission system (definition of offshore platform may need amending).

Clause 1.18

This paragraph and Figure 1.3 ought to be amended to illustrate the option where the GEP and OSP are on the HV side of the offshore platform transformers (offshore transformers and platform owned by Generator).

Figure 1.3

"GEP and GSP" should be "GEP and OSP".

Offshore Generation Circuit is not defined.

Clause 1.19

Drafting change: "... through ~~to~~ the *offshore transmission system* to the *interface point...*"

Clause 1.25

"... two or more *offshore transmission circuits* routed to different onshore substations..." – what about two or more *offshore transmission circuits* that connect at the same onshore substation but to different busbar sections that are either normally split or capable of being run split – do the onshore criteria of sections 4, 5 and 6 also apply to these cases?

Section 2 Generation Connection Criteria Applicable to the Onshore Transmission System

Clause 2.8.4

Why is this included in section 2? Generation connection criteria for offshore transmission systems are covered in Section 7 (see 7.14 for Generation Connection Capacity Requirements – Background Conditions).

Section 7 Generation Connection Criteria Applicable to an Offshore Transmission System

Concerns over cost benefit analysis approach and proposed minimum security criteria

We note the difference in approach used to identify offshore criteria compared to that used onshore i.e. cost benefit analysis compared with security-based criteria. It is perceived that lower levels of redundancy are required and justified in offshore networks due to their high costs and also due to the lower load factors of wind generation. We understand that the cost benefit approach was therefore used for offshore to investigate this perception and to evaluate and quantify appropriate levels of redundancy that should result in lowest cost to industry and consumers, without compromising the security of the transmission system.

However, we have very strong concerns that the proposed criteria do not represent the lowest cost solution, particularly regarding redundancy for offshore platform equipment (transformers and switchgear). We are concerned that the industry has not yet acquired enough accurate information about real capital and O&M costs of offshore plant and systems, nor about outage times (whether maintenance or failure and repair data), to feed into the cost benefit analysis.

The primary objective of the GBSQSS is to specify the minimum criteria that ensure the security and quality of the transmission system. We consider that there is scope to significantly reduce the requirements proposed for offshore platforms, and thereby reduce costs, whilst maintaining the required levels of transmission system security and quality. If extra redundancy is desired or justified (including the levels proposed), we believe this would best be assessed and requested by the customer, on a project by project basis. There will be greater chance that this approach will identify the lowest cost solution because cost benefit analysis on a project specific basis can take account, firstly, of the exact details and relevant factors for the project (as opposed to generic project assumptions), and secondly, of the real data on costs and outages that the industry accumulates over time.

Our views are supported by our own experience gained from real projects under construction and under development.

We make more detailed comments below. Some of these will also impact on Appendix A (Recommended Substation Configuration and Switching Arrangements).

General

We agree that requirements for power park modules greater than 1500MW or greater than 100km need to be considered and defined.

In the case of an offshore transmission system that connects mixed generation technologies (e.g. power park modules, single gas turbines and/or multiple gas turbines, is it always clear which criteria apply to each of the functional parts of the offshore transmission system?

Clause 7.2

The standard should clarify that capacity refers to cumulative capacity for a whole offshore transmission system (not 1500MW per module) and distance refers to connection (route) distance.

Offshore Grid Entry Point Capacity

We think the definition of offshore grid entry point capacity is open to interpretation. For example, in clause 7.8.1.1, it is not clear whether the requirement "50% of the *offshore grid entry point capacity*" applies on a per power park module basis, per power station basis, per platform basis or per offshore transmission system basis. i.e. are at least two transformers required for each PPM, each power station, each platform or each offshore transmission system?

Need for at least two AC transmission circuits on an offshore platform

We do not agree that the loss of power infeed for a planned or fault outage of a single AC offshore transmission circuit (e.g. a platform transformer) should be limited to 50% of the offshore grid entry point capacity (for power park modules) or zero (for gas turbines). This requirement necessitates at least two AC offshore transmission circuits (e.g. transformers) per platform and associated HV side switchgear (which introduces associated reliability and maintenance factors for that additional plant).

There are likely to be significant implications for the design of the platform, due to the size and weight of the additional equipment. Also, if two transformers are installed, what are the requirements for physical separation and isolation between them to prevent a major fault on one from affecting the other (e.g. some form of blast protection)?

We do not believe that maintenance requirements and unreliability of transformers are significant such that they justify the proposed requirements as a minimum, from either security or cost benefit considerations (depending on the details of the project). We recognise that many projects will need to use at least two transformers, due to available plant ratings, and this will automatically provide a significant level of redundancy. In other cases, project specific cost benefit analysis may show that although one large transformer may suffice, two smaller transformers are preferable.

Although platform transformers are not treated as generation circuits by definition, we believe they are analogous to the step-up transformers of synchronous generating units (which can operate with high load factors). In the latter case, we note that it is normal practice to install only a single transformer (even for units as large as 660MW) without risk to transmission system security.

Hence we believe that the minimum requirement should be to limit the loss of power infeed for a planned or fault outage of a single AC offshore transmission circuit to the normal infeed loss risk (1000MW), for all offshore generation. Redundancy above this minimum requirement should be left to the choice of the customer, as determined, for example, by project specific cost benefit analysis and/or by drawing on experience from previous projects.

<u>Double busbar switchgear on the offshore platform</u>

The standard requires double busbar switchgear on the LV and HV sides (where installed) of all offshore platforms. We do not agree that this blanket requirement is justified as a minimum requirement from either security or cost benefit considerations. Double busbar offshore substations do not seem to be being proposed by developers of current offshore wind projects. They are likely to have significant impacts on the design of the platform.

Instead, we believe that the loss of power infeed for a planned or fault outage of a busbar should be limited to the normal infeed loss risk (1000MW).

Secondly, we believe the double busbar arrangement will create difficulties for aggregating and registering multiple strings into a small number of power park modules. We note that a Power Park Module has a single electrical point of connection. With double busbars, it is possible to electrically separate any pair of strings. According to the definitions, we therefore don't see how it is possible to aggregate strings.

Further, if strings can be reconnected to different busbars, then this means that a whole PPM (together with its technical and BM data) may not always be directly mapped to a single busbar; alternatively, PPM data may have to be periodically updated to reflect the prevailing configuration of busbars and strings. The number of PPMs may even change (e.g. two may become three or four). Neither of these may be acceptable as a practical solution for the GBSO, OFTO and Generator in which case it might be necessary to register each string as a PPM and BMU, which defeats the objective of aggregation. At the very least, we would want a solution which permits aggregation of all the strings on say one half of a substation into one PPM/BMU, whilst keeping data revision and submission simple.

Clause 7.10

Some guidance is needed for other voltages above 132kV (e.g. 150kV).

Does offshore grid entry point capacity refer to the cumulative offshore grid entry point capacity per platform, or the cumulative offshore grid entry point capacity per offshore transmission system?

Need for at least two AC transmission circuits at the onshore connection substation

We make similar comments as for offshore platform transformers.

We consider that transformer unavailability, due to both planned and fault outages, is not high enough to justify the proposed minimum requirements.

Instead, we consider that the loss of power infeed for a planned or fault outage of a single AC offshore transmission circuit should be limited to the normal infeed loss risk (1000MW) i.e. the same requirement as applies in the case of DC converters. Any additional redundancy should be as requested by the customer.

Double busbar switchgear at the onshore connection substation

We make similar comments as for offshore substations.

Our own evaluations, based on real projects under development (where we have taken account of available land in the coastal environment, consents implications, and the need to install significant volumes of other equipment - particularly reactive compensation equipment), indicate that double busbar switchgear is not justified on the LV side (e.g. 150kV) onshore substation.

Hence we consider that the minimum requirement should be that the loss of power infeed for a planned or fault outage of a busbar should be limited to the normal infeed loss risk (1000MW).

At the interface point, we recognise that the onshore security requirements for the main interconnected transmission system will apply.

Section 8 Demand Connection Criteria Applicable to an Offshore Transmission System

We consider that some form of back-up supply is necessary, in the event of an outage of a main transmission connection to a platform, to provide for essential supplies to enable statutory requirements to be met and to safeguard the safety and health of people and plant.

We note Ofgem's proposal to introduce a requirement within the CUSC for an offshore generator to provide back-up supplies for the offshore generating units and the platform equipment owned by the generator and the OFTO. This proposal may have merits in that it is in the generator's interests to determine the optimum requirements and form of this supply, and also to ensure its regular maintenance so it will be reliable when required.

Conversely, the obligation to provide back-up supplies could be placed on the OFTO. This is sensible in that the OFTO's equipment required to provide back-up supplies would be located on the platform, which will also, most likely, be owned by the OFTO. The specification of the minimum requirements for the back-up supplies could be included either in the GBSQSS, or be determined by agreement

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on a project specific basis and included in the connection agreement or bilateral agreement. A potential benefit in placing an obligation on the OFTO for both main and back-up supply of demand is that the OFTO is better placed to determine exactly how much equipment is needed for the back-up supplies, taking into account the likely unavailability of the main supply, which is, to some extent, under its control. Operationally, the OFTO would also have an incentive to minimise the utilisation of an inefficient or expensive back-up supply by making repairs to the main supply as soon as possible (or using more efficient ways to provide redundancy).

We consider that the latter option is preferable: it is the OFTO's responsibility to plan for supply of demand via the main supply and it is sensible that the OFTO should plan for back-up supplies, to the required specification, in the event that the OFTO's main supply is unavailable.

These comments may also impact on Section 9 (Operation of an Offshore Transmission System).

Section 10 Voltage Limits in Planning and Operating an Offshore Transmission System

We are concerned about the wide steady-state voltage limits for systems below 132kV, in particular, at the offshore grid entry point. We cannot see that there is any proposed requirement to achieve better than +/-6% of nominal. In practice we are planning offshore systems to achieve operational voltages close to 1.0pu on the platform LV busbar (e.g. 33kV) under normal conditions. We expect that voltages within +/-2% of nominal can be achieved by a suitable on-load tapchanger specification for the offshore transformer.

It is important for the offshore LV busbar voltage to be tightly controlled. Some wind turbine manufacturers specify that the grid voltage at the turbine should be within +/-5% of nominal. A wider range of control, together with the voltage rise (or drop) along the string, could lead to unacceptable voltages at individual generating units.

Section 11 Terms and Definitions

Grid Entry Point (GEP)

Should not this definition apply to all power park modules, including onshore?

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<u>Offshore Platform</u>

Unclear definition: does "Offshore Platform" include only those platforms that are owned by an Offshore Transmission Owner? What does "high voltage" mean? Where are offshore platforms owned by the Generator included?

Appendix A Recommended Substation Configuration and Switching Arrangements

Some of the comments made earlier under Section 7 also apply here.

<u>Clauses A.3 and A.9</u>

Variations away from the guidance are permitted but only if they comply with the criteria set out in the main text of the standard. This appears to confirm that the requirements in the main standard are minimum criteria and that only those variations resulting in the same or higher levels of security and quality are permissible. Conversely, paragraphs 7.21 to 7.24, 8.12 to 8.15 and 9.3 appear to permit design variations that either increase or reduce security and/or quality.